Southwestern Public Service Company

Load Research Program

There are several steps that are required for Load Research sample design. These steps outlined and described below are consistent with the Load Research methods developed by the Association of Edison Illuminating Companies ("AEIC").

1. Accuracy

The accuracy of the load profile is a function of sample size and population variance. A design accuracy of ±10% at the 90% confidence level at the system and class peak time was specified in 1978 by Public Utility Regulatory Policies Act for all major rate classes. This is the recommended minimum requirement specified for any load profile and applies to the data used to develop the load profile (sample level or strata level).

The specific parameters of the sample design are outlined in the Code of Federal Regulations ("CFR"), which states:

> **Accuracy Level.** If sample metering is required, the sampling method and procedures for collecting, processing, and analyzing the sample loads, taken together, shall be designed so as to provide reasonably accurate data consistent with available technology and equipment. An accuracy of plus or minus 10 percent at the 90 percent confidence level shall be used as a target for the measurement of group loads at the time of system and customer group peaks.

2. Design (Auxiliary) Variable

The design variable must be known for each unit of the entire population. Possible choices for the auxiliary variable in load profile applications are:

- **Annual energy usage (used by Southwestern Public Service Company ("SPS"));**
- Monthly energy usage;
- Winter peak month energy usage;
- Summer peak month energy usage;
- Annual peak demand;
- Monthly peak demand;
- Summer peak demand;
- Winter peak demand;
- Type of appliances (electric heating or electric cooling);
- Type of residence or business; and
- Load factor.

3. **Sampling Methodology**

Several types of sampling procedures are commonly used to select individual sampling locations representative of a target population. The method chosen depends on the load characteristics to be estimated, the information available about the population, the uniformity of the population, and other sampling and budget constraints.

- Stratified random sampling **(used by SPS)**
  Divides the population into mutually exclusive, non-overlapping groups called strata. This type of sampling can involve stratifying in one or more dimensions.
- Census (100%) sampling **(used by SPS)**
  A stratum that contains a few customers that account for a large amount of load is a viable candidate for census sampling.

4. **Determining the Number of Strata and the Strata Boundaries**

The number of strata can often be determined for stratified random designs by calculating the coefficient of variation of the sampling distribution for test designs with different numbers of strata. The strata boundaries can be calculated by using the Dalenius-Hodges procedure or MBSS "strong stratification" as well as the analyst's judgment.

5. **Determining Sample Size**

The sampling method, estimation technique and required accuracy all influence sample size requirements. Sample size equations require estimates of the mean and variance of the variable of interest or an auxiliary variable. The preferred method of obtaining estimates for sample design is to derive them from prior load research data. When prior load research data are not available, a common procedure is to use an auxiliary variable (such as consumption) to estimate the mean and variance of the variable of interest.

Minimum requirements for sample size should be determined by the sampling method, estimation technique, and the chosen accuracy level plus a percentage margin to compensate for missing data. Sample sizes should be determined in such a way as to ensure accuracy for each month, not just the peak periods.

6. **Allocation**

There are two types of allocation techniques commonly used in load research sample design. Proportional allocation assigns sampling points to each stratum based upon the number of population units represented in the stratum. Neyman Allocation assigns sampling points to each stratum based upon the percentage of the total population standard deviation represented by the stratum.

7. **Accounting for Data Loss**

Since data will not be available for every customer during every time period in the study due to events such as equipment malfunction, human errors, customers moving, and customers requesting removal of recording equipment, techniques should be considered to account for data loss in the sample. There are two methods of accomplishing this. One technique is to apply a data loss factor which increases the overall sample size by a fixed percentage. Another technique is to set a minimum number of sample points per stratum and increase the sample size accordingly after allocation. The minimum number is a function of the data loss factor and research judgment. (No minimum requirement given). Sample participant attrition is also accounted for by SPS.

8. Selection of Alternate Sample Points

Once all efforts to install a particular metering site have failed, selecting sample replacements becomes necessary. Replacements are chosen in one of three ways: (1) replacements randomly chosen at the time of sample selection, (2) replacements systematically chosen at the time of sample selection, or (3) customers with similar information (usage, demographic, geographical location) chosen as backups. Any replacement method chosen should minimize sample bias.

9. Validation

After a prospective sample is chosen, it should be compared to the population to determine how well it represents the population, thus ensuring that the sample selection procedure has been performed correctly and that the appropriate sampling frame has been used. There are several methods of performing this validation. The simplest is to compare the sample mean usage to the population mean usage (annual or monthly). A more complex procedure involves setting specific tolerance ranges which the sample must meet for specific variables. Samples are then selected until a suitable sample is found. A third method is to select numerous samples and choose the sample that best matches the population for specific variables.

10. Customer Solicitation

Many utilities seek the customer's agreement to participate even though, legally, such an agreement may not be necessary. Therefore, there are three alternatives to customer solicitation: customer approval required, customers notified but approval not required, or customers not notified. Since customer rejection could introduce sampling bias, care should be taken when choosing the method of customer solicitation. Bias is the difference between the mean value of the estimate and the true value being estimated. Sampling bias occurs when some members of the population about which inferences are to be made are accidentally or purposely excluded from the population frame.

Southwestern Public Service Company

Description of Company

Southwestern Public Service Company, a New Mexico corporation ("SPS"), is an electric utility company and wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a utility holding company that was incorporated under the laws of Minnesota in 1909. Xcel Energy, through its subsidiaries, is a major U.S. electric and natural gas company, with annual revenues of more than $11.5 billion. Based in Minneapolis, Minnesota, Xcel Energy operates in eight western and mid-western states. Xcel Energy provides a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2 million natural gas customers. Through a subsidiary, Xcel Energy Transmission Holding Company, LLC, Xcel Energy also owns three transmission-only operating companies: Xcel Energy Southwest Transmission Company, LLC; Xcel Energy Transmission Development Company, LLC; and Xcel Energy West Transmission Company, LLC, all of which are either currently regulated by the Federal Energy Regulatory Commission ("FERC") or expected to be regulated by FERC. In terms of customers, Xcel Energy is the fourth-largest combination electric and natural gas company in the nation.

SPS serves approximately 127,000 New Mexico electric customers (404,000 total company) in a 52,000 square mile area of the Panhandle and the South Plains of Texas, as well as eastern and southern New Mexico. SPS has no non-regulated activities. Its service area has a customer density of 7.7 customers per square mile. The total electric customer count is comprised of: 73.7% New Mexico Residential customers (75.1% total company Residential customers), 17.6% New Mexico Commercial and Industrial customers (17.6% total company Commercial and Industrial customers), 7.3% New Mexico Lighting customers (6.2% total company Lighting customers), and 1.4% New Mexico Municipal and School customers (1.1% total company Municipal and School customers). SPS also serves five production transmission wholesale customers.

SPS's service territory is primarily agricultural, with large areas of oil and gas production. The oil and natural gas segments have been growing rapidly. SPS serves most of the cities and towns within the service territory, while many areas outside those towns are served by rural electric cooperatives.

The agricultural areas are mostly irrigated by pumping from natural underground water supplies. Crops include cotton, corn, grain sorghums, soybeans, and peanuts. Also, there is a large investment in cattle feeding operations in the service territory. The dairy and cheese industries are expanding within the service territory.

SPS is regulated by the 82 municipalities it serves in Texas, the Public Utility Commission of Texas, the New Mexico Public Regulation Commission and the FERC.

SPS is uniquely located relative to the electrical grid of North America. SPS is a member of the Southwest Power Pool, Inc. ("SPP"), which is a FERC-approved regional transmission organization. SPS is located in the southwest corner of SPP and the Eastern Interconnection. It is bordered to the west by the Western Electricity Coordinating Council ("WECC") and to the south and southeast by the Electric Reliability Council of Texas ("ERCOT").

SPS is interconnected with the Eastern Interconnection through eight synchronous transmission ties with the SPP. Three of these interconnections tie to utility operating company subsidiaries of American Electric Power Company with the SPS interconnections located near Elk City, Oklahoma (230 kV); Shamrock, Texas (115 kV); and Oklaunion, Texas (345 kV). Three of these interconnections tie to Oklahoma Gas and Electric Company with the interconnections located near Erick, Oklahoma (345kV) and two interconnections located near Balko, Oklahoma (345kV). One of these interconnections ties to Sunflower Electric Power Corporation near Holcomb, Kansas (345kV), and another one of these interconnections ties to Mid Kansas Electric Company near Guymon, Oklahoma (115kV).

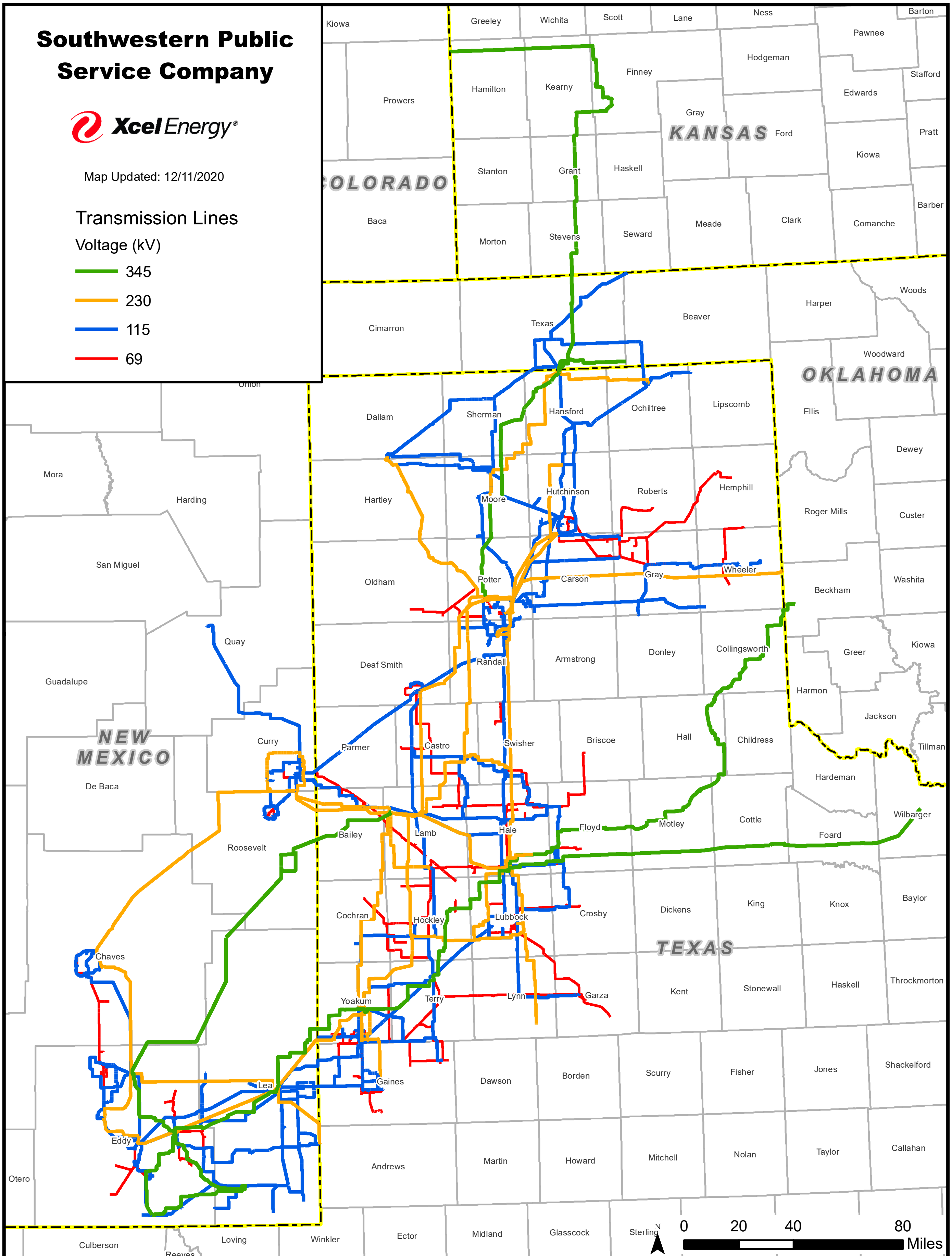
SPS is interconnected to the Western Interconnection through three high-voltage direct-current ("HVDC") converters owned by three utilities in the WECC. SPS is interconnected to the west jointly with El Paso Electric Company and Public Service Company of New Mexico ("PNM") at the Eddy County HVDC tie located near Artesia, New Mexico, and then with PNM solely in Roosevelt County, New Mexico at the Blackwater Draw HVDC tie located near Clovis, New Mexico. The third HVDC tie is with Public Service Company of Colorado, an Xcel Energy operating company, at the Lamar HVDC tie in Prowers County, Colorado.

SPS is not interconnected with ERCOT.

Xcel Energy

- Xcel Energy Inc. (MN - 1909)
  - 100% Northern States Power Company (Minnesota) (MN 2000)
    - 100% United Power and Land Company (MN 1924)
    - 32.8% Private Fuel Storage L.L.C. (DE 1995)
    - 100% NSP Nuclear Corporation (MN 1999)
  - 100% Northern States Power Company (Wisconsin) (WI 1901)
    - 90.18% Chippewa and Flambeau Improvement Company (WI 1909)
    - 100% Clearwater Investments, Inc. (WI 1991) See Clearwater Chart
    - 100% NSP Lands, Inc. (WI 1992)
  - 100% Xcel Energy Foundation (MN 2001)
  - 100% Southwestern Public Service Company (NM 1921)
  - 100% Public Service Company of Colorado (CO 1924)
    - 100% 1480 Welton, Inc. (CO 1958)
    - 100% Green and Clear Lakes Company (NY 1886)
    - 100% P.S.R. Investments, Inc. (CO 1985)
    - Beeman Irrigating Ditch and Milling Company 51% (CO 1878)
      Consolidated Extension Canal Company 53.5% (CO 1910)
      East Boulder Ditch Company 88.9% (CO 1865)
      Fisher Ditch Company 62.3% (CO 1921)
      Gardeners' Mutual Ditch Company 100% (CO 1915)
      Hillcrest Ditch and Reservoir Company 77.8% (CO 1918)
      Las Animas Consolidated Canal Company 76.6% (CO 1941)
      United Water Company 82% (CO 1916)
      (Also see PSCo Investments chart)
  - 100% WestGas InterState, Inc. (CO 1990)
  - 100% Xcel Energy International Inc. (DE 1997)
  - 100% Xcel Energy WYCO Inc. (CO 1999)
    - 50% WYCO Development L.L.C. (CO 1997)
  - 100% Xcel Energy Markets Holdings Inc. (MN 2000).
    - 100% e prime, inc. (CO 1995)
    - 47.5% Young Gas Storage Company Ltd. (CO 1993)
  - 100% Xcel Energy Communications Group Inc. (MN 2000)
    - 100% Seren Innovations, Inc. (MN 1996)
  - 100% Xcel Energy Retail Holdings Inc. (MN 2000)
    - 100% Xcel Energy Performance Contracting Inc. (MN 1993)
    - 100% Reddy Kilowatt Corporation (MT 1972)
  - 100% Xcel Energy Services Inc. (DE 1997)
  - 100% Xcel Energy Wholesale Group Inc. (MN 2000)
    - 100% Quixx Corporation (TX 1985) See Quixx Chart
  - 100% Xcel Energy Ventures Inc. (MN 2000)
    - 100% Eloigne Company (MN 1993) See Eloigne Chart
  - 100% Nicollet Project Holdings LLC (MN 2017)
    - 100% Nicollet Projects I LLC (MN 2017) See Nicollet Projects I Chart
    - 100% Nicollet Projects II LLC (MN 2017)
  - 100% Xcel Energy Transmission Holding Company, LLC (DE 2014)
    - 100% Xcel Energy West Transmission Company, LLC (DE 2014)
    - 100% Xcel Energy Southwest Transmission Company, LLC (DE 2014)
    - 100% Xcel Energy Transmission Development Company, LLC (DE 2014)
      - 100% Xcel Energy Acorn Transmission, LLC (DE 2018)
      - 100% Xcel Energy Birch Transmission, LLC (DE 2018)
  - 100% Xcel Energy Venture Holdings, Inc. (MN 2015)
    - 100% Xcel Energy Investments LLC (MN 2017)
    - 100% Energy Impact Fund Investment LLC (MN 2015)
  - 100% Nicollet Holdings Company, LLC (DE 2016)
    - 100% Nicollet Land Services, LLC (DE 2019)
    - 100% Capital Services, LLC (DE 2016)

Xcel Energy Inc. Legal Structure Chart
Last update: July 24, 2020
Effective as of: September 30, 2020



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Southwestern Public Service Company
Description of Company: Public Utility (electric)
List and Description of Affiliates
As of September 30, 2020

Line No.	Name	Description	Incorporated	Owner	Ownership %
1	**Xcel Energy Inc. (Xcel Energy)**	Holding Company.	MN - 1909		
2	**Northern States Power Co., a Minnesota Corporation**	Public utility (gas & electric).	MN - 2000	Xcel Energy Inc.	100.00%
3	NSP Nuclear Corporation	Holds NSP-MN's interest in Nuclear Management Co. LLC.	MN - 1999	NSP - MN	100.00%
4	Private Fuel Storage LLC	Development of private temporary spent nuclear fuel storage facility.	DE - 1995	NSP - MN	32.80%
5	United Power and Land Co. (UP&L)	Holds non-utility real estate.	MN - 1924	NSP - MN	100.00%
10	**Northern States Power Co., a Wisconsin Corporation (NSP-WI)**	Public utility (gas & electric).	WI - 1901	Xcel Energy Inc.	100.00%
11	Chippewa and Flambeau Improvement Co.	Operates hydro reservoirs in Wisconsin.	WI - 1909	NSP - WI	88.02
12	Clearwater Investments, Inc. (Clearwater Inv.)	Owns interests in affordable housing projects.	WI - 1991	NSP - WI	100.00%
13	Shoe Factory Holdings, LLC	Owns interests in affordable housing projects.	WI - 1994	Clearwater Inv	98.99%
14	NSP Lands Inc.	Holds non-utility real estate in Wisconsin.	WI - 1992	NSP - WI	100.00%
15	**Public Service Co. of Colorado (PSCo)**	Public utility (gas, electric & thermal).	CO - 1924	Xcel Energy Inc.	100.00%
16	PSR Investments Inc.	Owns certain life insurance policies acquired prior to 1986.	CO - 1985	PSCo	100.00%
17	1480 Welton Inc.	Holds real estate.	CO - 1958	PSCo	100.00%
18	Green and Clear Lakes Co.	Water storage for Cabin Creek hydro facility.	NY - 1886	PSCo	100.00%
19	Beeman Irrigating Ditch and Milling Co.	Cooling water for generating facilities.	CO - 1887	PSCo	51.00%
20	Consolidated Extension Canal Co.	Cooling water for generating facilities.	CO - 1910	PSCo	53.54
21	East Boulder Ditch Co.	Cooling water for generating facilities.	CO - 1865	PSCo	88.90%
22	Fisher Ditch Co.	Cooling water for generating facilities.	CO - 1921	PSCo	62.32
23	Gardeners' Mutual Ditch Co.	Cooling water for generating facilities.	CO - 1915	PSCo	100.00%
24	Hillcrest Ditch and Reservoir Co.	Cooling water for generating facilities.	CO - 1918	PSCo	77.80%
25	Las Animas Consolidated Canal Co.	Cooling water for generating facilities.	CO - 1941	PSCo	85.62
26	United Water Co.	Cooling water for generating facilities.	CO - 1916	PSCo	82.14
28	**WestGas InterState Inc.**	Natural gas transmission company.	CO - 1990	Xcel Energy Inc.	100.00%
29	**Xcel Energy Communications Group Inc. (Xcel Energy Comm.)**	Intermediate holding company for subsidiaries providing broadband telecommunications.	MN - 2000	Xcel Energy Inc.	100.00%
30	Seren Innovations Inc.**	Provides cable, telephone and high speed internet access.	MN - 1996 11-3-05 Calif. assets sold	Xcel Energy Comm	100.00%
31	**Xcel Energy Foundation**	Charitable activities.	MN - 2001	Xcel Energy Inc.	100.00%
32	**Xcel Energy International Inc. (Xcel Energy Intl.)****	Intermediate holding company for international subsidiaries.	DE - 1997	Xcel Energy Inc.	100.00%
33	**Xcel Energy Markets Holdings Inc. (Xcel Energy Mkts)**	Intermediate holding company for subsidiaries. providing energy marketing services	MN - 2000	Xcel Energy Inc.	100.00%

Southwestern Public Service Company
Description of Company: Public Utility (electric)
List and Description of Affiliates
As of September 30, 2020

Line No.	Name	Description	Incorporated	Owner	Ownership %
34	e prime Inc. (e prime)**	Unregulated commodity marketing affiliate.	CO - 1995	Xcel Energy Mkts	100.00%
35	Young Gas Storage Co. Ltd.	Owns and operates an underground gas storage.	CO - 1993	Xcel Energy Mkts	47.50%
36	**Xcel Energy Retail Holdings Inc. (Xcel Energy Retail)**	Intermediate holding company for subsidiaries providing services to retail customers.	MN - 2000	Xcel Energy Inc.	100.00%
37	Reddy Kilowatt Corporation	Energy sales and marketing services.	MT - 1972	Xcel Energy Retail	100.00%
38	Xcel Energy Performance Contracting Inc.	Holds contracts related to energy conservation.	MN - 1993	Xcel Energy Retail	100.00%
39	**Xcel Energy Services Inc. (Xcel Energy Svcs.)**	Service company for Xcel Energy system.	DE - 1997	Xcel Energy Inc.	100.00%
40	**Xcel Energy Ventures Inc. (Xcel Energy Ventures)**	Intermediate holding company for subsidiaries to develop and manage new business ventures.	MN - 2000	Xcel Energy Inc.	100.00%
41	Eloigne Co. (Eloigne)	Owns interests in affordable housing projects which qualify for low income housing tax credits.	MN - 1993	Xcel Energy Ventures	100.00%
42	Bemidji Townhouse LP	Owns interests in affordable housing projects.	MN - 5/3/93	Eloigne	99.00%
43	Chaska Brickstone LP	Owns interests in affordable housing projects.	MN - 10/7/97	Eloigne	99.99%
44	Cottage Court LP	Owns interests in affordable housing projects.	MN - 6/23/94	Eloigne	99.00%
45	Crown Ridge Apartments LP	Owns interests in affordable housing projects.	MN - 2/16/96	Eloigne	99.99%
46	Dakotah Pioneer LP	Owns interests in affordable housing projects.	ND - 4/20/99	Eloigne	99.99%
47	Edenvale Family Housing LP	Owns interests in affordable housing projects.	MN - 8/29/97	Eloigne	99.99%
48	Fairview Ridge LP	Owns interests in affordable housing projects.	MN - 12/20/93	Eloigne	99.00%
49	Farmington Family Housing LP	Owns interests in affordable housing projects.	MN - 2/16/99	Eloigne	99.99%
50	Farmington Townhome LP	Owns interests in affordable housing projects.	MN - 2/15/98	Eloigne	99.99%
51	Hearthstone Village LP	Owns interests in affordable housing projects.	ND - 9/14/97	Eloigne	99.00%
52	J&D 14-93 LP	Owns interests in affordable housing projects.	MN - 1/3/94	Eloigne	99.00%
53	Lauring Green LP	Owns interests in affordable housing projects.	MN - 8/14/89	Eloigne	99.00%
54	Links Lane LP	Owns interests in affordable housing projects.	MN - 8/11/93	Eloigne	99.00%
55	Lyndale Avenue Townhomes LP	Owns interests in affordable housing projects.	MN - 5/6/99	Eloigne	99.99%
56	Mahtomedi Woodland LP	Owns interests in affordable housing projects.	MN - 12/3/96	Eloigne	99.00%
57	Mankato Townhomes I LP	Owns interests in affordable housing projects.	MN - 6/20/97	Eloigne	59.99%
58	Marvin Garden LP	Owns interests in affordable housing projects.	MN - 4/1/94	Eloigne	99.00%
59	Moorhead Townhomes LP	Owns interests in affordable housing projects.	MN - 9/8/99	Eloigne	99.99%
60	Park Rapids Townhomes LP	Owns interests in affordable housing projects.	MN - 6/17/95	Eloigne	99.99%
61	Rochester Townhome LP	Owns interests in affordable housing projects.	MN - 2/5/98	Eloigne	99.00%
62	Rushford Housing LP	Owns interests in affordable housing projects.	MN - 3/27/96	Eloigne	99.99%
63	Safe Haven Homes LLC	Owns interests in affordable housing projects.	DE - 1997	Eloigne	100.00%
64	Shade Tree Apartments LP	Owns interests in affordable housing projects.	MN - 6/11/99	Eloigne	99.99%
65	Shakopee Boulder Ridge LP	Owns interests in affordable housing projects.	MN - 10/20/98	Eloigne	99.99%
66	Shenandoah Woods LP	Owns interests in affordable housing projects.	MN - 8/29/97	Eloigne	99.99%
67	Sioux Falls Partners LP	Owns interests in affordable housing projects.	SD - 9/2/94	Eloigne	99.00%

Southwestern Public Service Company
Description of Company: Public Utility (electric)
List and Description of Affiliates
As of September 30, 2020

Line No.	Name	Description	Incorporated	Owner	Ownership %
68	St. Cloud Housing LP	Owns interests in affordable housing projects.	MN - 1/13/03	Eloigne	99.99%
69	Tower Terrace LP	Owns interests in affordable housing projects.	MN - 5/9/94	Eloigne	99.00%
70	**Xcel Energy Wholesale Group Inc. (Xcel Energy Wholesale)****	Intermediate holding company. for subsidiaries providing wholesale energy	MN - 2000	Xcel Energy Inc.	100.00%
71	Quixx Corporation (Quixx Corp.)**	Energy related projects.	TX - 1985	Xcel Energy Wholesale	100.00%
72	Quixx Carolina Inc. (Quixx Carolina)**	Energy related projects.	TX - 1995	Quixx Corp.	100.00%
73	Quixxlin Corp. (Quixxlin)**	Energy related projects.	DE - 1997	Quixx Corp.	100.00%
74	**Xcel Energy WYCO Inc. (Xcel Energy WYCO)**	Finances and holds 50% interest in WYCO Development LLC.	CO - 1999	Xcel Energy Inc.	100.00%
75	WYCO Development LLC	Acquire, own and lease natural gas transportation facilities.	CO - 1997	Xcel Energy WYCO	50.00%
76	**Xcel Energy Transmission Holding Company, LLC (Xcel Energy Transmission Holding Company)**	Intermediate holding company for subsidiaries providing energy transmission services.	DE - 2014	Xcel Energy Inc.	100.00%
77	Xcel Energy Southwest Transmission Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
78	Xcel Energy Transmission Development Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
79	Xcel Energy Acorn Transmission, LLC	Provide transmission services.	DE - 2018	Xcel Energy Transmission Development Company, LLC	100.00%
80	Xcel Energy Birch Transmission, LLC	Provide transmission services.	DE - 2018	Xcel Energy Transmission Development Company, LLC	100.00%
81	Xcel Energy West Transmission Company, LLC	Energy transmission services.	DE - 2014	Xcel Energy Transmission Holding Company, LLC	100.00%
82	**Xcel Energy Venture Holdings, Inc.**	Holdling Company.	MN - 2015	Xcel Energy Inc.	100.00%
83	Energy Impact Fund Investment LLC	Energy Investment.	MN - 2015	Xcel Energy Venture Holdings, Inc.	100.00%
84	Xcel Energy Investments LLC	Energy Investment.	MN - 2017	Xcel Energy Venture Holdings, Inc.	100.00%
85	**Nicollet Holdings Company, LLC**	Holding Company.	DE - 2016	Xcel Energy Inc.	100.00%
86	Capital Services, LLC	Internal Support Service.	DE - 2016	Nicollet Holdings Company, Inc.	100.00%
87	Nicollet Project Holdings LLC	Holding Company.	MN - 2017	Xcel Energy Inc.	100.00%
88	**Southwestern Public Service Company**	Public Utility.	NM - 1921	Xcel Energy Inc.	100.00%
90	Nicollet Projects I LLC	Energy generation investment.	MN - 2017	Nicollet Project Holdings LLC	100.00%
91	Betcher CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
92	Foreman's Hill CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
93	Grimm CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
94	Heyer CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%

Southwestern Public Service Company
Description of Company: Public Utility (electric)
List and Description of Affiliates
As of September 30, 2020

Line No.	Name	Description	Incorporated	Owner	Ownership %
95	Huneke CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
96	Johnson I CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
97	Johnson II CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
98	Krause CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
99	RJC I CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
100	RJC II CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
101	Scandia CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
102	School Sisters CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
103	Webster CSG LLC	Owns and operates community solar garden in Minnesota.	MN - 2018	Nicollet Projects I LLC	100.00%
104	Nicollet Projects II LLC	Energy generation investment.	MN - 2017	Nicollet Project Holdings LLC	100.00%

Notes: ** Company is being classified as in discontinued operations.

THE FUTURE IN SIGHT

2019 ANNUAL REPORT

Xcel Energy®

FIFTEEN YEARS OF EARNINGS EXCELLENCE

It's a 15th anniversary of providing excellent shareholder value worth celebrating.

Xcel Energy achieved its earnings target once again in 2019, marking the 15th consecutive year of meeting or exceeding our earnings guidance.

"It's an outstanding track record that few companies in our peer group can match," said Bob Frenzel, Xcel Energy's President and Chief Operating Officer. "Shareholders have been — and continue to be — attracted to our story of solid, dependable earnings growth. Our capital investment strategy that is driving the clean energy transition continues to pay dividends for our shareholders."

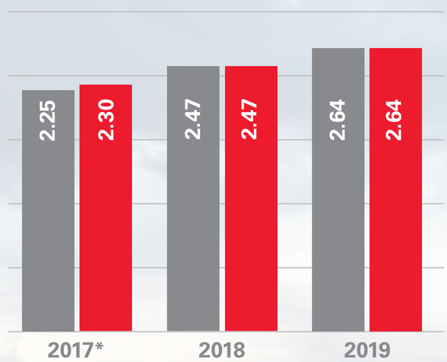
The company's 15-year Total Shareholder Return is 531% compared to 378% for our peer group. We also increased your dividend in 2019, extending the streak of dividend growth to 16 consecutive years. The combination of solid dividends and strong earnings growth has driven our Total Shareholder Return, significantly outpacing our peer group.

FINANCIAL HIGHLIGHTS

	2018	2019
Total GAAP earnings per share	2.47	2.64
Ongoing earnings per share	2.47	2.64
Dividends annualized	1.52	1.62
Stock price (close)	49.27	63.49
Assets (millions)	45,987	50,448

EARNINGS PER SHARE

Dollars per share (diluted)



GAAP (generally accepted accounting principles) earnings per share

Ongoing earnings per share

*A reconciliation to GAAP earnings per share is located in Item 7 of the 2017 Form 10-K.

COMPANY DESCRIPTION

Xcel Energy is a major U.S. electric and natural gas company with annual revenues of $11.5 billion. Based in Minneapolis, Minnesota, the company operates in eight states and provides a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2 million natural gas customers.

DEAR FELLOW SHAREHOLDERS:

Outstanding financial results and strong operational performance are on the long list of 2019 accomplishments for Xcel Energy. The company made significant strides in several areas — enhancing the customer experience, driving continuous improvement, embracing innovation and, of course, leading the clean energy transition.

In late 2018, we became the first U.S. electricity company to announce a vision to produce 100% carbon-free electricity by 2050. Since our announcement, several public utilities have declared similar goals, indicating the industry has a strong appetite to prepare for a carbon-free future.

This year we made good progress toward our interim goal of reducing carbon emissions 80% by 2030 — we're more than halfway there — and expect to achieve that goal by retiring coal plants early, adding more wind and solar, extending the license of our Monticello Nuclear Generating Station, using natural gas to ensure reliability, and expanding energy efficiency programs. New dispatchable carbon-free technologies need to be developed to remove the last 20% of carbon, and Xcel Energy is leading the industry's efforts to advocate for research and development.

We chose "The Future In Sight" as the theme for the report because we've set plans in place to move away from coal while taking care of impacted employees — through retraining and reassignments — and impacted communities by driving economic development opportunities. The future is also in sight as we transform the customer experience, from modernizing the electrical grid to developing electricity pricing, infrastructure and charging programs to make it easy for customers to switch to electric vehicles.

Of course, those efforts to build the future supplement our core responsibility to deliver safe, reliable, affordable and clean energy to our customers and the outstanding performance that our shareholders have come to expect.

OUTSTANDING FINANCIAL PERFORMANCE

For the 15th consecutive year, we met or exceeded our earnings guidance. We delivered 2019 earnings of $2.64 per share, at the top end of our original earnings guidance range, compared to $2.47 per share in 2018.

Xcel Energy also increased your dividend by 6.6%, or 10 cents annually in 2019, extending our streak of dividend growth to 16 consecutive years. We maintained our earnings and dividend objective of 5 to 7% annual growth, which reflects our confidence in our long-term financial plan.

As a result of our continued strong performance, our one-year total shareholder return exceeded 32% in 2019, outpacing our peer group. We also compare favorably to our peer group for three-, five- and 10-year performance results. In addition, our stock price (ticker: XEL) closed at an all-time high of $65.82 in September and has subsequently set several new all-time highs in early 2020, closing above $71 per share.

Due to the sound execution of our strategic priorities — leading the clean energy transition, enhancing the customer experience and keeping bills low — we remain well positioned to deliver for our shareholders in 2020 and beyond.

STEEL FOR FUEL EXECUTION

As part of our Steel for Fuel growth strategy, we continue to build carbon-free wind farms that save money for our customers by avoiding future fuel costs. In 2019, we added more than 700 megawatts of company-owned wind capacity through the completion of three wind farms: Hale in Texas, Foxtail in North Dakota and Lake Benton in Minnesota. Developing — and owning — wind projects has become a core competency that provides excellent investment opportunities for our shareholders. These projects also stimulate the economy in rural areas through jobs, tax base and landowner lease payments (see story on pages 5-6).

Additionally, seven company-owned wind projects continue in various stages of construction. Six of these projects are on pace to be completed before the end of 2020 to take full advantage of the federal production tax credit before it begins to phase down. Our ability to forecast wind energy for optimum efficiency allows us to save money for our customers.

We're also executing our Steel for Fuel strategy by acquiring expiring wind energy PPAs (power purchase agreements) and rebuilding those wind farms with the latest advanced wind technology. Lake Benton was a PPA acquisition, and we received regulatory approval for the Jeffers and Community Wind North repowering projects in southern Minnesota. We anticipate more repowering acquisition opportunities in 2020 and beyond as numerous PPA contracts expire during the next decade. We plan to make significant investments in large-scale solar starting in the mid-2020s.

By the end of 2021, we expect to grow our wind ownership by fivefold compared to 2016. While our wind portfolio continues to expand, our carbon emissions continue to fall — declining 10% last year, the largest one-year reduction (5.6 million tons) since the clean energy transition began. At the end of 2019, we had lowered our carbon emissions from the electricity serving customers 44% since 2005.

DEVELOPING AN INNOVATIVE SPIRIT

We know we can't achieve our vision to produce 100% carbon-free electricity by 2050 without the development of technologies that either don't yet exist or aren't commercially viable today. Although we are taking an agnostic approach to technology — letting the best ideas rise to the top — it doesn't mean we are simply waiting for others to do the heavy lifting.

A cross-functional team of Xcel Energy employees has collected data and prioritized 34 emerging technologies into five categories. Some of the promising dispatchable carbon-free options include the next generation of nuclear technology, carbon capture at fossil plants, advanced renewable and storage options and using hydrogen in applications both in the utility industry and across the economy.

We are partnering with the Idaho National Lab on a pilot program at one of our generating stations to use carbon-free nuclear energy to produce hydrogen. We are also working closely with EPRI, our industry research and development consortium, to support promising technologies, and have implemented flexible operations at our nuclear and coal facilities, using them less often on high renewable output days to reduce carbon and save customers money.

Developing new technologies is critical for our entire industry and for the nation as we transition away from carbon. In my role as incoming chairman for the Edison Electric Institute, our industry trade association, making significant progress on this issue will be a key part of my platform.

Innovation has been a focus of our organization for the last few years. Our employees have led the charge to find new and innovative ways to drive continuous improvement throughout our business. This cultural mindset is now ingrained in how we systematically approach our work. These ideas have led to $170 million of ongoing savings with more to come.

TRANSFORMING THE CUSTOMER EXPERIENCE

An innovative spirit also permeates our approach to transforming the customer experience. Competition continues to rise, and when our customers face a choice, we want them to choose us. Last year, we kicked off our plans to transform the customer experience and completed foundational work in several areas.

We partnered with industry leader Itron to develop state-of-the-art smart meters to build the energy grid of the future that will improve reliability and offer customers real-time information to manage their energy use (see page 11). We also advanced foundational work to improve the experience when new customers sign up for service, expanded our electric vehicle program with new filings in several states (see pages 9-10) and developed more coverage options for our HomeSmart® appliance repair plan.

Customers appreciate the opportunity to make choices, both in terms of choosing their energy supply mix and the way they engage with us. More than 200,000 customers participated in renewable programs in 2019, and we sold out our Solar*Connect Community program in Wisconsin. Improvement to our customers' digital experience is evidenced by our automated phone system that handled more than 60% of customer calls with high customer satisfaction. At the end of 2019, more than 625,000 customers had downloaded our mobile app that provides outage information and the opportunity for customers to pay their bill and communicate with us.

DELIVERING ON THE FUNDAMENTALS

Although we focus a great deal of time and energy on our strategic priorities, we never lose sight of our core mission to provide the safe, reliable and affordable electricity and natural gas you count on every day.

Electric system reliability was second quartile and exceeded 99.9%, improving on last year's strong performance. In recognition of our track record of restoring service to customers quickly, we received two EEI Emergency Recovery Awards for our efforts following the Colorado bomb cyclone in March and a South Dakota tornado in September.

By adding staff and using GPS technology to better assign our crews, we delivered our best-ever performance in natural gas emergency response times for the fifth consecutive year — a 6% improvement over 2018, and a 25% improvement since 2014. Xcel Energy recently joined ONE Future, a consortium of natural gas companies working to voluntarily reduce methane emissions below 1%, by 2025.

Ensuring public safety is a critical aspect of our work, one that is important to all stakeholders, and we are positioned to build on this performance. We also reevaluated our employee safety program with a growing focus to prevent life-altering injuries.

Our nuclear performance was industry leading in 2019, with both generating stations receiving the highest ratings available from regulators. Last year, despite our national leadership in renewable energy, our nuclear fleet provided nearly half of the company's carbon-free electricity, and the fleet produced the second-highest generation output in its history, all while reducing costs for the fourth consecutive year.

REGULATORY PROGRESS

Strong nuclear performance is paramount and positions us favorably as we request a 10-year license extension for our Monticello Nuclear Generating Station as part of our proposed plan to achieve our 80% carbon-reduction goal. Nuclear energy is essential to achieve our clean energy plans, and our plants have never performed better. The Minnesota commission is reviewing our proposal that also includes the early retirement of all coal in Minnesota by 2030, the addition of wind and solar and the utilization of natural gas to enhance system reliability.

In early 2020, the company closed on a $650 million transaction to purchase the Mankato Energy Center — a 760-megawatt natural gas combined-cycle facility in southern Minnesota — from Southern Power as a non-regulated asset. We believe the agreement will help ensure reliability as we retire our coal fleet and allows us to integrate more renewable energy on our system. Although this investment is not included in rate base, it is expected to generate "utility like" returns over its life.

In Colorado, we continue to implement the Colorado Energy Plan and moved forward with our newest wind project in the state, the 500-megawatt Cheyenne Ridge Wind Farm that will be completed this year to earn the full production tax credit.

Another significant accomplishment was getting transmission access for the 522-megawatt Sagamore Wind Farm in New Mexico — scheduled to be completed in 2020 — despite significant logistical challenges. We also achieved constructive rate case outcomes in most jurisdictions, the result of successful stakeholder outreach.

EMPLOYEES LEAD THE WAY

Successful outcomes don't just happen, they are the result of thousands of hours of effort from our teams of dedicated employees.

I'm proud to lead a team of more than 11,000 strong, committed to delivering for our stakeholders. We bring an innovative spirit to work each day and understand the importance of powering the lives of millions of residential and business customers. These efforts are gaining national recognition. We were named as one of *Fortune* magazine's "World's Most Admired" companies for the seventh consecutive year, one of *Corporate Responsibility Magazine's* 100 Best Corporate Citizens and among *Newsweek's* Most Responsible Companies. Recent honors include the S&P Global Award of Excellence and 2020 Climate Leadership Award for our clean energy leadership and progress in reducing carbon emissions.

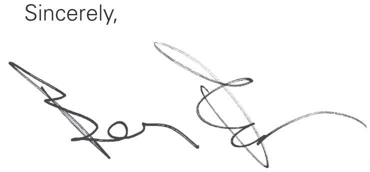
Working for a values-based organization is important to our employees. Earlier this year, *Ethisphere* named us one of 2020's World's Most Ethical Companies®. That award reflects a clear understanding of our values — Safe, Trustworthy, Connected and Committed — and our commitment to our recently refreshed Code of Conduct that guides our decision-making principles.

Just as doing the right thing every day is important, giving back to communities is also ingrained in our DNA. Last year our employees, boosted by matching dollars from the Xcel Energy Foundation, donated more than $3.4 million and 73,000 volunteer hours to community organizations that they care about.

On multiple fronts — from our carbon-free vision to our customer experience transformation to preparing for a world when electric vehicles gain significant market share — the future is clearly in sight. It's a future we strive for every day, while never losing sight of our obligation to deliver safe, clean, reliable and affordable energy today.

We enter the 2020s with momentum, optimism and appreciation. Thanks for your continued partnership and the trust you place in us.

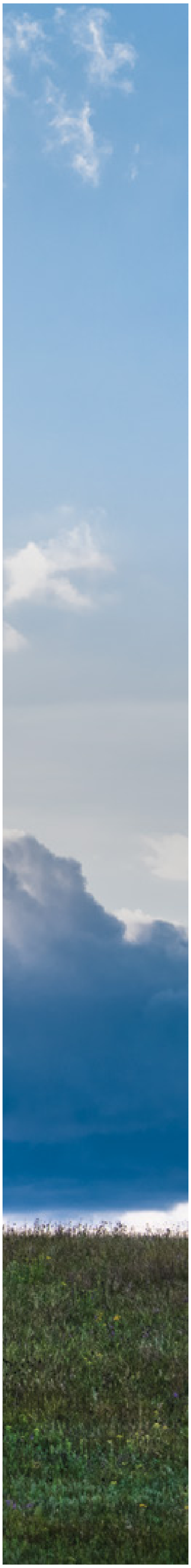
Sincerely,



Ben Fowke
Chairman and Chief Executive Officer

WIND FARMS DRIVE RURAL ECONOMIC DEVELOPMENT

NORTH DAKOTA PROJECT WILL GENERATE $30 MILLION OF LANDOWNER LEASE PAYMENTS AND PROVIDE TAX BENEFITS FOR STATE AND LOCAL GOVERNMENTS



GROWING UP ON her family farm outside of Ellendale, North Dakota, Geraldine Blumhardt spent her formative years helping with chores while her parents tended to the cattle and a variety of crops — mostly wheat, small grains and hay.

Fast forward five decades. Geraldine's family no longer farms the land but generates income by renting it to local ranchers and farmers. Geraldine and her sister Violet Rasch, who co-owns the property, never expected their farmland would generate additional income from a non-farming source like wind energy.

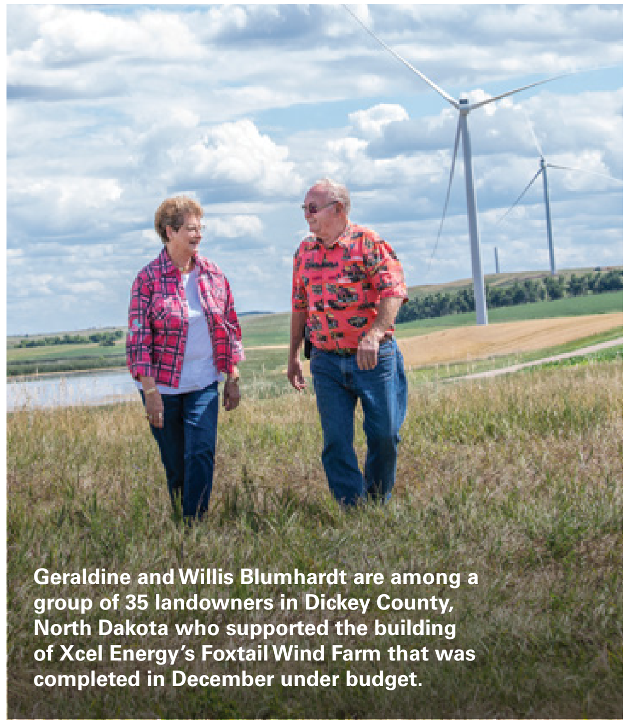
Geraldine and her sister are among a group of 35 landowners in Dickey County who came together to support the development of Foxtail Wind Farm, Xcel Energy's newest wind project that will generate more than $30 million in landowner lease payments over the life of the project and produce enough carbon-free renewable energy to power 80,000 average-sized homes annually.

"We negotiated a fair price," Geraldine said about her decision to allow Xcel Energy to build eight of the 75 wind towers on 1,200 acres of her property. "We're not big spenders — we will probably invest the proceeds somehow."

Preliminary work for the project including substation construction and building access roads and tower foundations began in 2018, but all tower assembly took place during the last eight months of 2019. "I was surprised by how big the wind tower components are and how fast they could be assembled," she said.

The landowners aren't the only ones who are benefitting financially from the wind project, which created 100 construction jobs and 10 full-time operational positions. Foxtail is expected to provide more than $20 million of additional revenue for state and local governments and the nearby school district, and generate significant customer savings.

"Our wind projects provide significant economic and environmental benefits," said Sean Lawler, a

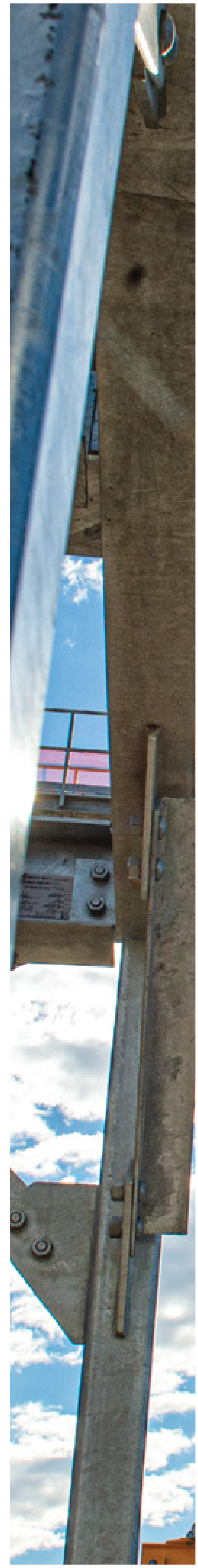


Geraldine and Willis Blumhardt are among a group of 35 landowners in Dickey County, North Dakota who supported the building of Xcel Energy's Foxtail Wind Farm that was completed in December under budget.

Siting and Land Rights Agent who led communication efforts with landowners during the construction of Foxtail and continues to lead outreach efforts. "The county, local businesses and the school district have all benefitted from Foxtail and will continue to do so for decades."

Foxtail is the first Xcel Energy wind project that will feature an Aircraft Detection Lighting System that activates red blinking lights on the wind towers only when an aircraft is in the immediate area, otherwise keeping the night skies dark.

Xcel Energy is currently developing the largest multi-state wind expansion in the country — with approximately 15 projects that have been completed or are under construction. This includes building new farms and repowering older farms with new technology. By the end of 2021, we will own 73% of the 4,800 megawatts of wind capacity on our system. Wind energy plays an important role in our efforts to reduce carbon emissions 80% by 2030 and produce 100% carbon-free electricity by 2050.



IN 2018 XCEL ENERGY became the first major electricity provider in the country to announce a vision to produce 100% carbon-free electricity by 2050. On the path to carbon-free energy, we also announced an interim goal of achieving an 80% carbon reduction from 2005 levels by 2030 while enhancing reliability and ensuring affordability.

"Our carbon-free vision has been well received by our stakeholders. One of the benefits of being the first company to announce our vision is that we have a seat at the table and can help shape public policy, which will play an important role in our success," said Ben Fowke, Xcel Energy's Chairman and CEO. "Several other public utilities have followed our lead and have announced similar goals."

Company engineers believe we can achieve the 80% interim goal by 2030 using existing technologies. Removing the last 20% of carbon will require carbon-free dispatchable resources that currently don't exist or are not commercially viable. A cross-functional Xcel Energy team has studied 34 technologies in five priority areas in our efforts to partner with our industry peers to develop and promote solutions that work for all of us. Possible solutions could include longer-term battery storage, advanced nuclear, hydrogen or carbon capture at natural gas facilities.

To achieve our 2030 goal, we expect to take a balanced approach to our energy supply. Our Upper Midwest Energy Plan proposal in front of the Minnesota Public Utilities Commission includes expanding energy efficiency programs, retiring all coal plants in Minnesota by 2030, adding 5,000 megawatts of wind and solar energy, extending the operating license for our Monticello Nuclear Generating Station by a decade — from 2030 to 2040 — and adding natural gas and battery storage.

"Nuclear energy is an important part of the equation because it's the only 24x7 carbon-free dispatchable resource available. Natural gas provides important qualities for grid health. It's an important fuel source that allows us to integrate more renewable energy and continue to deliver the reliability our customers expect," Fowke said.

Natural gas produces approximately half the carbon output as coal plants. After receiving approval through an unregulated subsidiary in early 2020, we closed on the acquisition of the $650 million Mankato Energy Center, a 760-megawatt natural gas facility in southern Minnesota that helps ensure reliability and allows us to integrate more renewable energy on our system.

"The Mankato Energy Center acquisition provides long-term value to our customers and shareholders, especially as we accelerate the retirement of coal plants," said Paul Johnson, Vice President, Investor Relations, noting the facility is the largest natural gas operation in the company's portfolio.

The company continues to develop resource plans in all the territories we serve. We expect to file a Colorado resource plan in late 2020 or early 2021.

A BALANCED APPROACH

MIX OF RENEWABLE ENERGY SOURCES, COMBINED WITH NUCLEAR AND NATURAL GAS, KEY TO ACHIEVING 80% CARBON REDUCTION

The Cherokee Generating Station is a natural gas combined-cycle plant in Denver, Colorado. Natural gas allows us to incorporate more renewables and ensure reliability.

Xcel Energy employees Barb Jerhoff and Tom Santori visit along Metro Transit's new C Line in Minneapolis that is supported by electric buses. Barb manages the relationship between Xcel Energy and Metro Transit and Tom develops new programs to support electric vehicles.

ELECTRIC BUSES ARRIVE IN MINNEAPOLIS

COMPANY DEVELOPING ELECTRIC VEHICLE PROGRAMS IN MULTIPLE STATES TO SUPPORT HOME CHARGING, PUBLIC CHARGING AND FLEET ELECTRIFICATION

THE FIRST ELECTRIC BUSES manufactured in Minnesota are quietly transporting passengers in the Twin Cities using electricity supplied by Xcel Energy.

Metro Transit purchased eight New Flyer electric buses that were built in St. Cloud, Minnesota at a manufacturing facility powered by Xcel Energy natural gas. The 60-foot buses charge overnight at a Metro Transit garage in the Twin Cities but can also charge at an outdoor charging station if they need to be topped off during the day.

"The rollout of electric buses in the state is another visible sign that electric vehicles continue to gain traction in Minnesota and across our service territory," said Tom Santori, who develops programs to support the company's EV efforts. "Electric buses are much more quiet than traditional buses, and the feedback from riders and neighbors on the C Line electric bus route has been overwhelmingly positive. It's a better experience for everyone."

Xcel Energy is working closely with our regulators to develop electric vehicle programs to serve our customers who are looking for ways to save money on gas and maintenance and simultaneously reduce their carbon footprint. Electric vehicles that charge overnight during off-peak hours cost less than the equivalent of $1 per gallon of gas, and their carbon emissions are one-third lower than gasoline-powered vehicles. Those emissions will continue to drop as Xcel Energy strives to reduce carbon emissions 80% by 2030.

"In addition to Minnesota, we have plans for electric vehicle programs in Colorado, New Mexico and Wisconsin," Santori said. "We completed significant foundational work in 2019 and expect 2020 will be a big year for EVs and Xcel Energy."

The company is focusing its EV efforts in three areas: home charging, public charging and fleet electrification. In January 2020, the company rolled out a pilot home charging subscription service. The first 100 customers who signed up with one of our auto dealer partners received an advanced level 2 charger installed in their garages and have unlimited overnight charging in their homes for approximately $44 a month.

"We are providing innovative solutions for our customers," said Kevin Schwain, director of Xcel Energy's EV program. "We want to make the experience of charging your car as easy and affordable as possible."

Several communities and businesses are partnering with Xcel Energy to evaluate the costs and benefits of converting at least part — if not all — of their fleets to electric vehicles.

"Companies want to lower their fuel costs, but many are concerned about their carbon footprint and view converting their fleets to electric vehicles an important part of their sustainability program," Schwain said.

INNOVATION AT THE HEART OF ADVANCED GRID INITIATIVE

SMART METERS WILL LEAPFROG EXISTING TECHNOLOGY, HELP CUSTOMERS MANAGE ENERGY CONSUMPTION AND SAVE MONEY ON THEIR MONTHLY ENERGY BILLS

OF ALL THE TRANSFORMATIVE Xcel Energy projects under development, nothing dovetails with the theme of this report — The Future In Sight — better than our Advanced Grid Intelligence and Security initiative.

Advanced Grid is an extensive, multi-year project to modernize the electric power grid with a series of new capabilities that will improve outage restoration, provide customers real-time data to better manage their energy use and give employees new tools to more effectively work with customers and efficiently manage and protect the grid.

Some parts of the original electric grid — an interconnected series of substations, transmission lines and distribution wires that deliver electricity from power plants to customers — are more than 100 years old. Foundational work to modernize the grid is underway in Colorado and Minnesota. Early learnings from Colorado were used to develop a proposal that is currently under review by the Minnesota Public Utilities Commission.

Colorado customers began to see benefits from Advanced Grid with the installation of the Advanced Distribution Management System in 2020. Additional benefits will begin in 2021 when the first "smart meters" are installed in a rollout that will wrap up in 2024. The new meters developed by our strategic partner Itron — an industry leader — will leapfrog existing technology and pave the way for customers to better understand and control their energy usage and save money.

Itron meters, for example, may have the ability to show customers exactly how much money they can save by running their appliances at night after peak demand has declined instead of right after supper when electricity prices are higher. You may also be able to tell your teenagers exactly how much money they are wasting by leaving their electronics on.

Our customers will also appreciate the ability for Xcel Energy to better isolate outages when storms disrupt the grid. Advanced Grid communications technology will greatly minimize the number of consumers affected by an outage by utilizing automatic restoration technology. The smaller number of customers who lose power should expect faster restoration times as the modern grid will better isolate the issue so our employees can start and complete repairs sooner.

Employees will enjoy new tools to help them balance the system and more efficiently distribute power. One new technology, called Integrated Volt Var Optimization, will help reduce energy consumption from the first customer adjacent to a substation to the last customer at the end of the line, saving customers money.

Private, two-way wireless communication is a key tenet of the modern grid and must be protected by a robust cybersecurity platform. The Advanced Grid system is designed to integrate several layers of cyber protection to ensure reliability and protect customer data.

"The future is indeed within sight — as early as this year in Colorado, and we expect it will arrive in Minnesota next year," said Brett Carter, EVP and Chief Customer and Innovation Officer. "Advanced Grid will be our largest customer experience transformation in the near term, but the customer benefits will last for decades."

A DECADE OF PROGRESS

	2009	2019
Carbon reduction	10%	44%
Wind ownership	124 MW	2,121 MW
Ongoing EPS per share	$1.50	$2.64
Stock price	$21.22	$63.49
Market cap	$9.7 billion	$33.3 billion

* Year-end numbers

NOT ONLY WAS 2019 an excellent year for Xcel Energy, it wrapped up an excellent decade — a decade of progress. By numerous measurements, Xcel Energy delivered outstanding results in the 2010s. Leading the clean energy transition delivered significant economic and environmental benefits.

When the decade began, large-scale wind energy was still a nascent technology. At the end of 2009, wind accounted for less than 10% of our energy mix, and we only owned a tiny fraction — 124 megawatts. By the end of 2019, our wind ownership portfolio — an outcome of our Steel for Fuel growth strategy to deliver low-cost wind energy to our customers and provide investment opportunities for shareholders — had grown to approximately 2,100 megawatts, a 20-fold increase.

Building large infrastructure projects, like wind farms and the transmission lines needed to bring wind energy to market, requires capital. Fortunately, thanks to our track record of strong financial performance, generating capital has not been a challenge for this organization.

"The tripling of our stock price and corresponding 243% growth in market capitalization during the 2010s reinforce the fact that shareholders like our story of dependable earnings and dividend growth and support our strategy to make significant investments to lead the clean energy transition," said Ben Fowke, Chairman and CEO.

Our efforts to transition away from fossil fuels to renewable energy — primarily wind and solar — also delivered environmental benefits. By the end of 2019, we had reduced carbon emissions 44% from a 2005 baseline. At the start of the decade, that number was only 10%.

And through all of our work to provide safe, reliable and affordable electricity every day, we made a sizeable economic impact in our communities. More than 60% of the $35 billion we spent in the last decade was with companies based in our service territory, and $3.6 billion was with diverse suppliers.

Giving back to our communities that we are privileged to serve is just as important. In the last 10 years, our foundation granted more than $73 million to charitable organizations. And that number does not include the countless volunteer hours we gave to our communities.

"It's exciting to look back on our progress, but I'm even more optimistic about the future and progress we will make in the next decade," Fowke said.

PROTECTING POLLINATORS

Schoolchildren from Kulm, North Dakota help plant pollinator-friendly milkweed at the Foxtail Wind Farm in Dickey County.

UNDER THE MASSIVE wind towers on the North Dakota plains, you can find a smaller, more subtle energy source that is also important for the environment.

When Xcel Energy built the Foxtail Wind Farm in 2019, the company made sure that pollinators living in the area have plenty of milkweed and pollinator-friendly vegetation to help our crops thrive. Children from the Kulm School District in Dickey County helped Xcel Energy team members plant the pollinator garden at the Foxtail Wind Farm.

Although Foxtail is the first example of planting pollinator habitat at an Xcel Energy wind farm, we've been helping pollinators for close to a decade. We've created more than 2,100 acres of pollinator habitat in Minnesota, North Dakota and Wisconsin — with plans to keep planting. Our 45 pollinator sites range from as little as one acre to 800 acres on Xcel Energy land and company-owned right-of-way acreage. The pollinator gardens and native prairie habitats are located under transmission lines, near substations and other power-generating facilities or office buildings.

According to the U.S. Fish and Wildlife Service, more than 75% of our food crops rely on pollinators to survive. Pollinators including bees, butterflies, some birds and even bats are vital to flowering plant reproduction for producing most fruits and vegetables, and their population is shrinking.

"Our pollinator program is a partnership with state and federal agencies, communities and non-profit organizations," said Pam Rasmussen, who manages the program for Xcel Energy. "We see opportunities for educating and engaging interested customers and landowners who are also eager to make a difference by creating pollinator habitat in their own backyards."

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, 2019 or

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

001-3034
(Commission File Number)

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
414 Nicollet Mall Minneapolis Minnesota	**55401**
(Address of Principal Executive Offices)	(Zip Code)

612 330-5500
(Registrant's Telephone Number, Including Area Code)

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

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

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

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

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

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

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

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

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

As of June 28, 2019, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $30,629,347,167 and there were 514,865,476 shares of common stock outstanding.

As of Feb. 13, 2020, there were 524,669,024 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive Proxy Statement for its 2020 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

PART I

ITEM 1 — BUSINESS

Definitions of Abbreviations

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

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

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
IRS	Internal Revenue Service
Minnesota District Court	U.S. District Court for the District of Minnesota
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of the Attorney General
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EECRF	Energy efficiency cost recovery factor
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor

Other

ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
Boulder	City of Boulder, CO
C&I	Commercial and Industrial
CACJA	Clean Air Clean Jobs Act
CAISO	California Independent System Operator
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CBA	Collective-bargaining agreement
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEO	Chief executive officer
CFO	Chief financial officer
CEP	Colorado Energy Plan
CIG	Colorado Interstate Gas Company, LLC
CPCN	Certificate of public convenience and necessity
CWA	Clean Water Act
CWIP	Construction work in progress
DECON	Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level.
DRC	Development Recovery Company
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
EPU	Extended power uprate
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas

HDD	Heating degree-days
IM	Integrated market
IPP	Independent power producing entity
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
JOA	Joint operating agreement
LSP Transmission	LSP Transmission Holdings, LLC
MDL	Multi-district litigation
MEC	Mankato Energy Center
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOI	Notice of Inquiry
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PI	Prairie Island nuclear generating plant
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right-of-first-refusal
ROU	Right-of-use
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
Standard & Poor's	Standard & Poor's Ratings Services
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCEH	Texas Competitive Energy Holdings
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
THI	Temperature-humidity index
TOs	Transmission owners
TransCo	Transmission-only subsidiary
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity
WOTUS	Waters of the U.S.

Measurements

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

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 2020 EPS guidance, long-term EPS and dividend growth rate, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information.

The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2019 (including the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs, changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

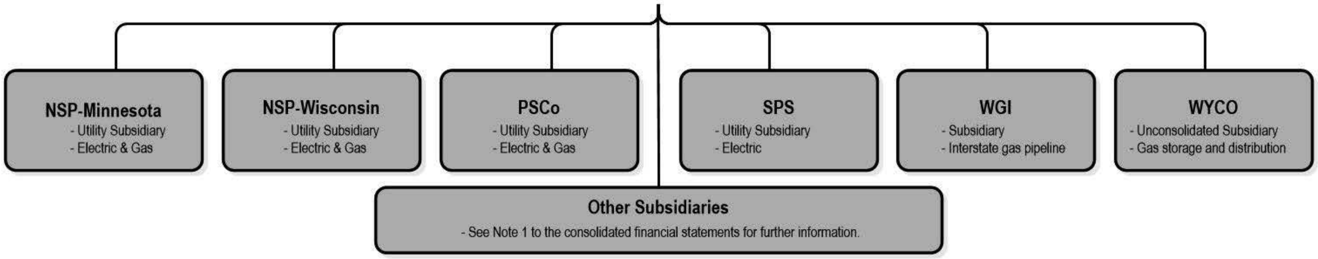
Where to Find More Information

Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov.

Overview

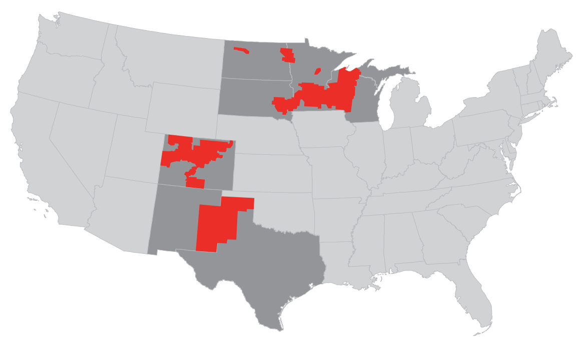
Xcel Energy is a major U.S. regulated electric and natural gas delivery company headquartered in Minneapolis, Minnesota (incorporated in Minnesota in 1909). The Company serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Xcel Energy provides a comprehensive portfolio of energy-related products and services to approximately 3.7 million electric customers and 2.1 million natural gas customers through four utility subsidiaries (i.e., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS). Along with the utility subsidiaries, the transmission-only subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations. The Company's significant nonregulated subsidiaries are Eloigne, Capital Services and Nicollet Holdings.

Xcel Energy®



Utility Subsidiaries' Service Territory

Electric customers	3.7 million
Natural gas customers	2.1 million
Total assets	$50.4 billion
Electric generating capacity	18,730 MW
Electric transmission lines (conductor miles)	108,238 miles
Electric distribution lines (conductor miles)	207,524 miles
Natural gas transmission lines	2,177 miles
Natural gas distribution lines	35,624 miles
Natural gas storage capacity	53.4 Bcf



Vision, Mission and Values

VISION To be the preferred and trusted provider of the energy our customers need

OUR VALUES
One team powered by many

CONNECTED
Innovate together. Celebrate together.
Always put we before me – we win as a team.
Value the diversity that each of us brings – be inclusive.

COMMITTED
Act like an owner.
Never settle – be curious and find a better way.
Keep customers and communities the center of all we do.

SAFE
Safety always – no exceptions.
Be responsible for each other's safety.
Do your part to keep communities safe.

TRUSTWORTHY
Give respect, earn respect.
Keep your word – integrity matters.
Do the right thing – lead by example.

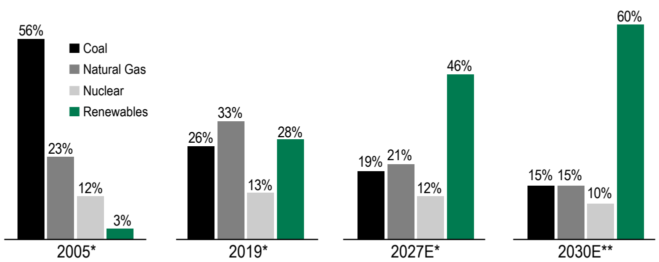
MISSION To provide our customers the safe, clean, reliable energy services they want and value at a competitive price

Strategic Priorities

Lead the Clean Energy Transition

For more than a decade, Xcel Energy has proactively managed the risk of climate change and increasing customer demand for renewable energy through a clean energy strategy that consistently seeks to reduce carbon emissions and aims to transition our operations for the future. We have successfully reduced our carbon emissions from generation serving our customers by nearly 44% from 2005 to 2019 and we are on track to reach 60% renewable generation by 2030. We expect to reduce our carbon footprint by 80% by 2030 (over 2005 levels) and aspire to serve all customers with 100% carbon-free electricity by 2050.

Energy Mix – 80% Carbon Reduction by 2030



* Remaining includes hydro, biomass and other sources; future-year estimates dependent on various factors
** Potential scenarios that achieve carbon reduction goal

In addition to increasing our renewable generation, Xcel Energy is transitioning how we produce, deliver and encourage the efficient use of energy by:

- Offering energy efficiency programs;
- Retiring coal units and modernizing generating plants; and
- Advancing power grid capabilities.

We are working to add over 4,700 MW of wind energy to our system by 2021, including 3,500 MW of owned wind and 1,200 MW of PPAs. Of the 3,500 MW of owned wind, 1,300 MW are now in service and 2,200 MW are under development or construction. This will bring our total wind capacity to over 11,000 MW by 2021.

Our long-term plan includes the addition of approximately 5,000 MW of solar energy by the early 2030s, 275 MW of battery storage and a potential ten-year extension of our Monticello nuclear plant. It also includes the retirement of multiple coal units totaling approximately 2,000 MW. Xcel Energy plans to continue to evaluate its coal fleet for other potential early retirements as part of state resource plans or other regulatory proceedings.

Enhance the Customer Experience

Customers' energy expectations continue to evolve and Xcel Energy is committed to providing the options and solutions they want and value.

Xcel Energy continues to expand its renewable energy production and offerings, and further develop and promote DSM and conservation programs. Over the past decade, the Company has spent over $2.1 billion on these programs.

We are also in the process of transforming our electric grid to accommodate increased levels of renewables, distributed energy resources and corresponding data growth, while maintaining high levels of reliability and security.

We have partnered with policymakers, state agencies and innovative companies to develop nation-leading electric vehicle solutions for our customers. We are preparing for a substantial amount of electric vehicles on roads across our service territory by 2030 and are focused on providing helpful information, making installations simple and keeping customer bills affordable through new rates and programs. We anticipate offering innovative programs for electric vehicle customers in Minnesota, Wisconsin, and Colorado this year. We are filing comprehensive Transportation Electrification Plans in both Colorado and New Mexico in the coming year.

We continue to develop and deliver new renewable energy solutions for our residential and C&I customers who want more directly sourced energy. Through programs such as Renewable*Connect® and Windsource®, we match our customers' needs without them needing to add expensive or on-site equipment.

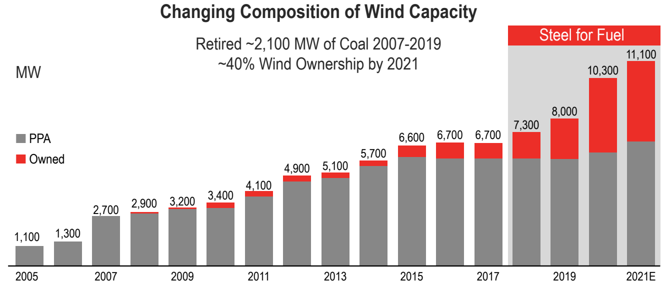
Keep Bills Low

Affordability is critical part of our customers' experience. We are focused on the impact our operations, regulation and legislation have on their bills. Our objective is to keep bill increases at or below the rate of inflation.

Our utility service territories benefit from the geographic concentration of favorable renewable resources. Strong wind and high solar generation capacity factors lower the lifetime cost of these resources. This, coupled with renewable tax credits and avoided fuel costs, enables us to invest in more renewable generation, in which the capital costs are largely or completely offset by fuel savings. We call this our "Steel for Fuel" strategy.

Steel for Fuel not only expands the Company's renewable portfolio, but allows delivery of carbon-free energy without raising customer bills through replacement of fossil fuel generation or fuel-free wind and solar.

Changing Composition of Wind Capacity



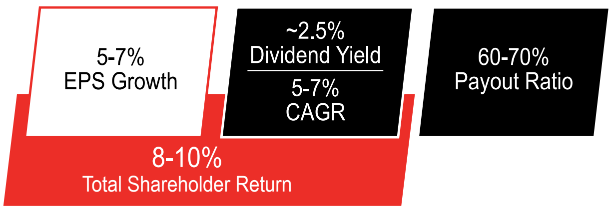
Xcel Energy is working to keep long-term O&M expense relatively flat without compromising reliability or safety. We intend to accomplish this objective by continually improving processes, leveraging technology, proactively managing risk and maintaining a workforce prepared to meet the needs of our business today and tomorrow.

O&M declined 0.6% in 2019 even as we took the opportunity to invest more in key strategic and operational areas, including reducing operational risks and enhancing our customers' experience. While Xcel Energy continues to invest prudently in appropriate areas, we remain committed to our long-term objective of improving operating efficiencies and taking costs out of the business.

Deliver a Competitive Total Return to Investors and Maintain Strong Investment Grade Credit Rating

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

Through our disciplined approach to business growth, financial investment, operations and safety, we are well positioned to continue delivering on our value proposition.



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

Our ongoing earnings have grown 6.1% annually since 2005 and our dividend has grown 6.3% annually from 2013-2019. We work to maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range. Our current ratings are consistent with this objective.

Environmental, Social and Governance Leadership

Xcel Energy has consistently demonstrated industry leadership in mitigating climate, operational and financial risks, while remaining committed to our customers, communities, employees and investors. We have delivered tangible environmental, social and governance results in alignment with our four corporate values - committed, connected, safe and trustworthy.

Environmental

Xcel Energy has been the number one U.S. wind provider for 12 of the past 14 years.

We continue to lead the industry with one of the most aggressive carbon reduction goals among our peers. Our plans to achieve 80% reduction by 2030 are aligned with Paris Accord goals and have been independently validated by an Intergovernmental Panel on Climate Change expert.

In December 2018, Xcel Energy became the first major electric utility in the country to announce an aspiration to produce 100% carbon-free electricity for customers by 2050.

Social

Xcel Energy works to mitigate the employee and community impacts of early plant retirements. We provide affected employees with advanced notice and offer retraining and relocation opportunities. Through these efforts and natural attrition, Xcel Energy has had no layoffs as a result of plant retirements.

We have also worked to foster economic sustainability and continued affordability through partnering with communities, policymakers and customers impacted by coal plant retirements, to build facilities and attract new businesses. Examples include:

- Near our Sherco plant, scheduled to close by 2030, we are partnering with local leadership and a major data center to locate a $600 million data center. Additionally, Xcel Energy actively worked to relocate a metal recycling plant near our plant; and
- We retained Evraz Steel in Colorado, a major Pueblo employer, by partnering with the company and community to create an affordable solar solution to meet their needs.

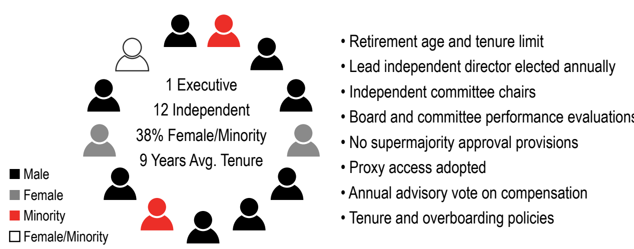
Xcel Energy is an active community member. We recognize and carefully evaluate the broader potential economic impacts of our decisions and work to proactively support the people and economic health of our communities. In 2019, we spent $3.1 billion locally, donated nearly $11 million to local charities, continued to offer employees 40 hours of volunteer paid time off annually and our employees served on over 500 non-profit boards. Donations include Xcel Energy employee and Xcel Energy Foundation gifts.

As a member of diverse communities, we value and celebrate diversity and inclusion. For example:

- Xcel Energy has offered domestic partner benefits since 1995;
- The Company's CEO has signed the Action for Diversity & Inclusion Pledge, for the advancement of diversity and inclusion within the workplace, and Xcel Energy has an employee-led Diversity & Inclusion Council;
- We have been selected among the nation's top corporations for lesbian, gay, bisexual, transgender, and queer equality by earning a perfect score on the Human Rights Campaign's 2019 Corporate Equality Index for the past 4 years; and
- Xcel Energy was named to the 2019 Military Times Best for Vets Employers rankings for the sixth straight year and currently employs more than 1,000 veterans, nearly 10% of our workforce.

Governance

Xcel Energy has a diverse and qualified Board of Directors committed to effective governance.



The Company first adopted an environmental policy and instituted Board of Directors' oversight of environmental performance in 2000, followed by publication of our corporate responsibility report in 2005.

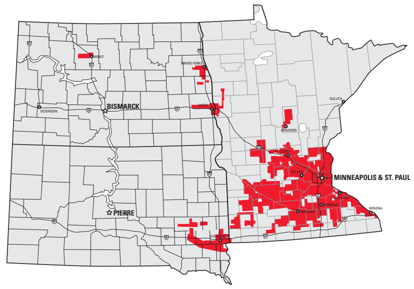
We consistently set aggressive goals and hold ourselves accountable, to our customers, our communities and our investors. Additionally, Xcel Energy was among the first U.S. utilities to tie carbon reduction directly to executive compensation over fifteen years ago and is one of three peer utilities who do so today.

We are also focused on safety for our employees and our communities. In 2019, 60% of annual incentive pay was tied to safety and system reliability. Employees at every level have "stop work authority" and are instrumental in keeping each other and our surrounding communities safe.

Utility Subsidiaries

NSP-Minnesota

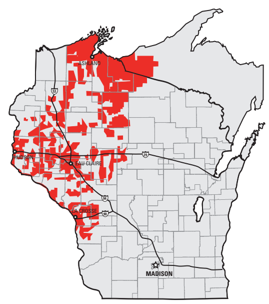
Electric customers	1.5 million
Natural gas customers	0.6 million
Consolidated earnings contribution	35% to 45%
Total assets	$19.9 billion
Rate Base	$11.2 billion
ROE	9.31%
Electric generating capacity	7,712 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	33,528 miles
Electric distribution lines (conductor miles)	80,186 miles
Natural gas transmission lines	86 miles
Natural gas distribution lines	10,518 miles



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

NSP-Wisconsin

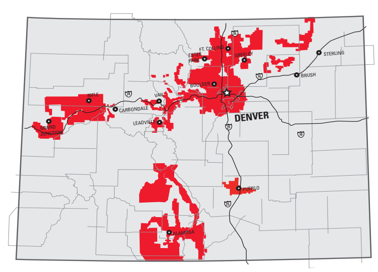
Electric customers	0.3 million
Natural gas customers	0.1 million
Consolidated earnings contribution	5% to 10%
Total assets	$2.8 billion
Rate Base	$1.7 billion
ROE	8.27%
Electric generating capacity	548 MW
Gas storage capacity	3.8 Bcf
Electric transmission lines (conductor miles)	12,285 miles
Electric distribution lines (conductor miles)	27,504 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	2,473 miles



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

PSCo

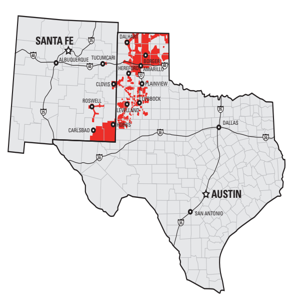
Electric customers	1.5 million
Natural gas customers	1.4 million
Consolidated earnings contribution	35% to 45%
Total assets	$19.0 billion
Rate Base	$12.4 billion
ROE	8.69%
Electric generating capacity	5,666 MW
Gas storage capacity	32.5 Bcf
Electric transmission lines (conductor miles)	24,008 miles
Electric distribution lines (conductor miles)	78,023 miles
Natural gas transmission lines	2,057miles
Natural gas distribution lines	22,633 miles



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

SPS

Electric customers	0.4 million
Consolidated earnings contribution	15% to 20%
Total assets	$7.9 billion
Rate base	$4.9 billion
ROE	9.71%
Electric generating capacity	4,804 MW
Electric transmission lines	38,418 miles
Electric distribution lines	21,810 miles



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

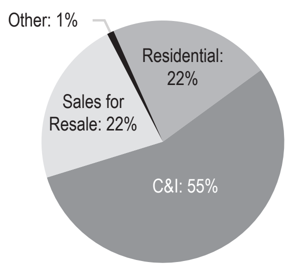
Operations Overview

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

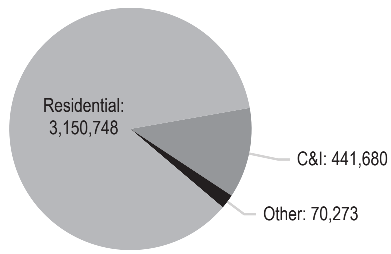
Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities across all four operating companies. Xcel Energy had electric sales volume of 116,317 (millions of KWh), 3,662,701 customers and electric revenues of $9,575 (millions of dollars) for 2019.

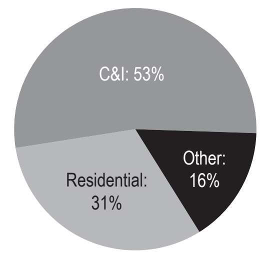
Sales Volume



Number of Customers



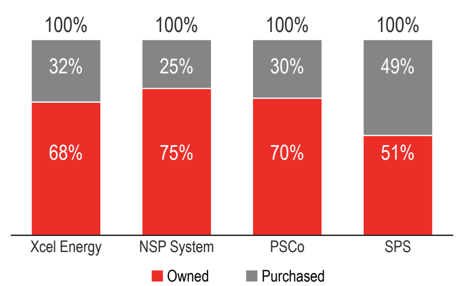
Revenues



Sales/Revenue Statistics

	2019	2018
KWh sales per retail customer	24,712	25,263
Revenue per retail customer	$2,244	$ 2,257
Residential revenue per KWh	11.97¢	11.78¢
Large C&I revenue per KWh	5.96¢	5.91¢
Small C&I revenue per KWh	9.43¢	9.21¢
Total retail revenue per KWh	9.08¢	8.93¢

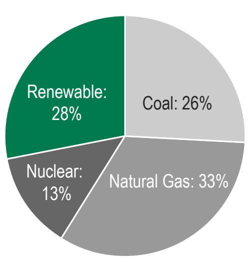
Owned and Purchased Energy Generation — 2019



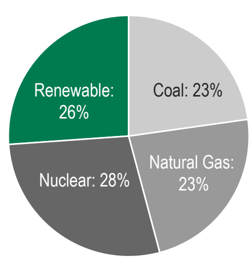
Electric Energy Sources

Total electric generation by source (including energy market purchases) for the year ended Dec. 31, 2019:

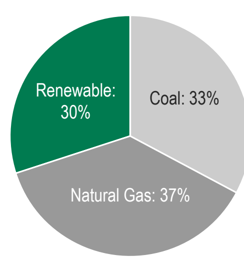
Xcel Energy



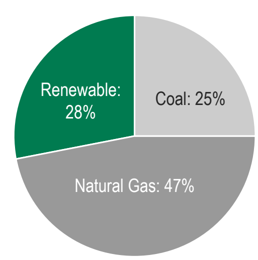
NSP System



PSCo



SPS



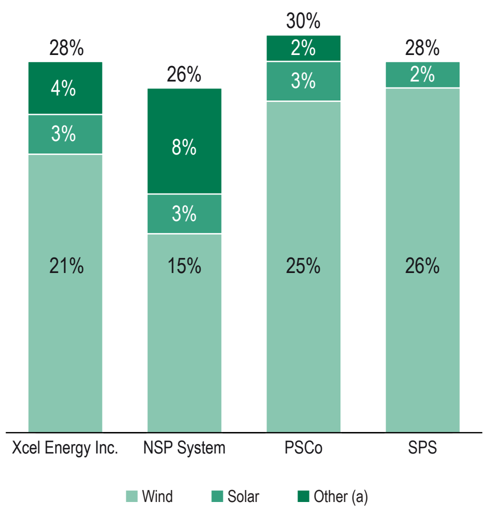
*Distributed generation from the Solar*Rewards® program is not included (approximately 538 million KWh for 2019)

Renewable Energy Sources

Xcel Energy's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. Renewable percentages will vary year over year based on system additions, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Renewable energy as a percentage of total energy for 2019:



(a) Includes biomass and hydroelectric

Wind Energy Sources

Owned — Owned and operated wind farms with corresponding capacity:

	2019		2018	
Utility Subsidiary	**Wind Farms**	**Capacity**	**Wind Farms**	**Capacity**
NSP System	7	1,090 MW	5	840 MW
PSCo	1	600 MW	1	600 MW
SPS	1	478 MW	—	—

PPAs — Number of PPAs with range:

	2019		2018	
Utility Subsidiary	**PPAs**	**Range**	**PPAs**	**Range**
NSP System	131	0.7 MW — 205.5 MW	132	0.7 MW - 205.5 MW
PSCo	20	2.0 MW — 300.5 MW	19	2.0 MW - 300.5 MW
SPS	18	0.7 MW — 250.0 MW	18	0.7 MW - 250.0 MW

Capacity — Wind capacity:

Utility Subsidiary	2019	2018
NSP System	2,780 MW	2,550 MW
PSCo	3,165 MW	3,160 MW
SPS	2,045 MW	1,565 MW

Average Cost (Owned) — Average cost per MWh of wind energy from owned generation:

Utility Subsidiary (a)	2019	2018
NSP System	$ 35	$ 37
PSCo	47	—

(a) The table reflects owned wind sites that were in commercial operation for the full calendar year. The Hale wind farm for SPS was put into service in June 2019 and the Rush Creek wind farm was put into service in December 2018.

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

Utility Subsidiary	2019	2018
NSP System	$ 41	$ 44
PSCo	41	43
SPS	25	26

Wind Energy Development

Xcel Energy is executing the largest multi-state wind investment in the nation and placed approximately 1,300 MW of owned wind and approximately 300 MW of PPAs into service during 2018-2019:

Project	Utility Subsidiary	Capacity
Rush Creek	PSCo	582 MW
Hale	SPS	460 MW
Foxtail	NSP-Minnesota	150 MW
Lake Benton	NSP-Minnesota	99 MW
Various PPAs	Various	~300 MW

As part of the multi-state wind investment, Xcel Energy currently has approximately 2,200 MW of owned wind under development or construction and approximately 900 MW of planned PPAs with an estimated completion date of 2021 or earlier:

Project	Utility Subsidiary	Capacity	Estimated Completion
Freeborn	NSP-Minnesota	200 MW	2020
Blazing Star 1	NSP-Minnesota	200 MW	2020
Blazing Star 2	NSP-Minnesota	200 MW	2020
Crowned Ridge (a)	NSP-Minnesota	200 MW	2020
Jeffers (b)	NSP-Minnesota	44 MW	2020
Community Wind North (b)	NSP-Minnesota	26 MW	2020
Dakota Range	NSP-Minnesota	300 MW	2021
Cheyenne Ridge	PSCo	500 MW	2020
Sagamore	SPS	522 MW	2020
Various PPAs	Various	~900 MW	2020 - 2021

(a) Build-own-transfer project.

(b) Repowering project.

Solar Energy Sources

Solar energy PPA(s):

Type	Utility Subsidiary	Capacity
Distributed Generation	NSP System	736 MW
Utility-Scale	NSP System	266 MW
Distributed Generation	PSCo	557 MW
Utility-Scale	PSCo	305 MW
Distributed Generation	SPS	10 MW
Utility-Scale	SPS	191 MW

Other Carbon-Free Energy Sources

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

See Item 2 — Properties for further information.

Nuclear Energy Sources

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2019 net summer dependable capacity that serves the NSP-System. Our nuclear fleet has become one of the safest and well-run in the nation, as rated by both the NRC and INPO.

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

Nuclear Fuel Cost

Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements:

Utility Subsidiary	Nuclear	
NSP System	Cost	Percent
2019	$ 0.81	45%
2018	0.80	45

Fossil Fuel Energy Sources

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

See Item 2 — Properties for further information.

Coal Energy Sources

Xcel Energy owns and operates nine coal plants with approximately 6,500 MW of total 2019 net summer dependable capacity.

Our operating companies have embarked on an industry-leading coal retirement program with permission from its key regulatory bodies.

Approved and proposed coal plant retirements:

Approved (2019 to 2027)			
Year	Utility Subsidiary	Plant	Capacity
2022	PSCo	Comanche 1	325 MW
2023	NSP-Minnesota	Sherco 2	682 MW
2025	PSCo	Comanche 2	335 MW
2025	PSCo	Craig 1	42 MW
2026	NSP-Minnesota	Sherco 1	680 MW

Proposed (2028 to 2030)			
Year	Utility Subsidiary	Plant	Capacity
2028	NSP-Minnesota	A.S King	511 MW
2030	NSP-Minnesota	Sherco 3	517 MW

Coal Fuel Cost

Delivered cost per MMBtu of coal consumed for owned electric generation and percentage of fuel requirements:

	Coal [(a)]	
Utility Subsidiary	Cost	Percent
NSP System		
2019	$ 2.02	36%
2018	2.13	42
PSCo		
2019	1.45	55
2018	1.45	62
SPS		
2019	2.19	45
2018	2.04	56

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

Natural Gas Energy Sources

Xcel Energy has 22 natural gas plants with approximately 7,900 MW of total 2019 net summer dependable capacity.

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

Natural Gas Cost

Delivered cost per MMBtu of natural gas consumed for owned electric generation and percentage of total fuel requirements:

	Natural Gas	
Utility Subsidiary	Cost	Percent
NSP System		
2019	$ 3.09	19%
2018	3.87	13
PSCo		
2019	3.27	45
2018	3.74	38
SPS		
2019	1.14	55
2018	2.24	44

Capacity and Demand

Uninterrupted system peak demand and occurrence date for the regulated utilities:

	System Peak Demand (in MW)			
Utility Subsidiary	2019		2018	
NSP System	8,774	July 19	8,927	June 29
PSCo	7,111	July 19	6,718	July 10
SPS	4,261	Aug. 5	4,648	July 19

Transmission

Transmission lines deliver electricity over long distances from power sources to transmission substations closer to homes and businesses. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support a diverse generation mix, including renewable energy. Xcel Energy owns more than 20,000 miles of transmission lines, serving 22,000 MW of customer load.

Transmission projects completed in 2019 include:

Project	Utility Subsidiary	Miles	Size
Maple River-Red River	NSP-Minnesota	5	115 KV
Nelson-Wabasha	NSP-Wisconsin	2	69 KV
Pawnee-Daniels Park	PSCo	125	345 KV
Thornton Substation	PSCo	2	115 KV
TUCO-Yoakum-Hobbs	SPS	64	345 KV
NEF-Cardinal	SPS	15	115 KV
Potash Junction-Livingston Ridge	SPS	15	115 KV
Mustang-Shell	SPS	9	115 KV
North Loving-South Loving	SPS	3	115 KV
Cunningham-Monument Tap	SPS	7	115 KV

Notable upcoming projects:

Project	Utility Subsidiary	Miles	Size	Completion Date
Huntley-Wilmarth	NSP-Minnesota	50	345 KV	2021
Bayfield Second Circuit	NSP-Wisconsin	19	35 KV	2022
Cheyenne Ridge	PSCo	65	345 KV	2020
TUCO-Yoakum-Hobbs	SPS	106	345 KV	2020
Eddy-Kiowa	SPS	34	345 KV	2020

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel from substations directly to homes and businesses in neighborhoods and cities around the country. Xcel Energy has a vast distribution network, owning and operating thousands of miles of distribution lines across our eight-state service territory, both above ground and underground.

To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure. Over the next five years, the Company will invest $1.4 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities. These investments will further improve reliability and reduce outage restoration times for our customers, while at the same time enabling new options and opportunities for increased efficiency savings. The new capabilities will also enable integration of battery storage and other distributed energy resources into the grid, including electric vehicles.

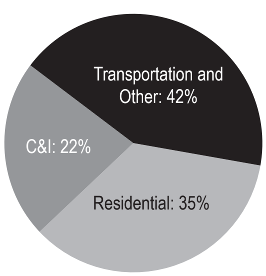
In 2019, Xcel Energy implemented foundational software and completed our initial smart meter deployment in Colorado as planned, with full-scale implementation to follow. We also requested approval to expand our advanced grid program to benefit our Minnesota customers and expect a Commission decision in late 2020. We plan to have smart meters implemented across our Colorado and Minnesota service territories by the end of 2024.

See Item 2 - Properties for further information.

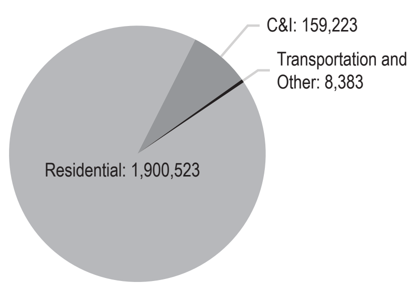
Natural Gas Operations

Natural gas operations consist of purchase, transportation and distribution of natural gas to end use residential, C&I and transport customers in NSP-Minnesota, NSP-Wisconsin and PSCo. Xcel Energy had natural gas deliveries of 463,185 (thousands of MMBtu), 2,068,129 customers and natural gas revenues of $1,868 (millions of dollars) for 2019.

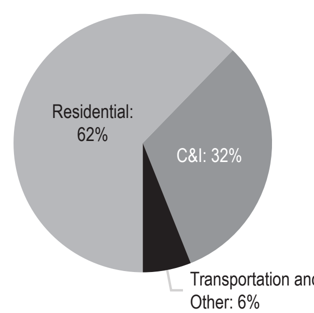
Deliveries



Number of Customers



Revenues



Sales/Revenue Statistics

	2019	2018
MMBtu sales per retail customer	129.31	120.51
Revenue per retail customer	$ 851.94	$ 785.86
Residential revenue per MMBtu	7.14	7.01
C&I revenue per MMBtu	5.73	5.76
Transportation and other revenue per MMBtu	0.57	0.80

Capability and Demand

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

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

	2019		2018	
Utility Subsidiary	MMBtu	Date	MMBtu	Date
NSP-Minnesota	897,615 (a)	Feb. 25	786,751	Jan. 12
NSP-Wisconsin	166,009 (a)	Jan. 30	159,700	Jan. 5
PSCo	2,139,420 (a)	March 3	1,903,878	Feb. 20

(a) Increase in maximum MMBtu output due to colder winter temperatures in 2019.

Natural Gas Supply and Cost

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

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

Utility Subsidiary	2019	2018
NSP-Minnesota	$ 3.71	$ 4.03
NSP-Wisconsin	3.49	3.84
PSCo	2.95	3.20

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

See Item 2 - Properties for further information.

General

General Economic Conditions

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

Seasonality

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

Competition

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

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

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

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Xcel Energy's wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load.

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

Xcel Energy Inc.'s utility subsidiaries have franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization.

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

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of MGP and other sites if it is determined that prior compliance efforts are not sufficient.

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

There are significant present/future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. We have undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If future environmental regulations do not take into consideration investments already made or if additional initiatives or emission reductions are required, substantial costs may be incurred.

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans for GHG reductions from coal-fired power plants. The state plans, due to the EPA in July 2022, will evaluate and potentially require heat rate improvements at existing coal-fired plants. It is not yet known how these state plans will affect our existing coal plants, but they could require substantial additional investment, even in plants slated for retirement. Xcel Energy believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

In 2019, Xcel Energy estimates that it reduced the carbon emissions associated with the electric generating resources, both owned and under PPAs, used to serve its customers by approximately 44% from 2005 levels.

Environmental Costs

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

Costs charged to operating expenses for nuclear decommissioning, spent nuclear fuel disposal, environmental monitoring and remediation and disposal of hazardous materials and waste were approximately:

- $345 million in 2019;
- $335 million in 2018; and
- $315 million in 2017.

Average annual expense of approximately $400 million from 2020 – 2024 is estimated for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements were approximately:

- $30 million in 2019;
- $50 million in 2018; and
- $60 million in 2017.

See Item 7 — Capital Requirements for further discussion.

Capital Spending and Financing

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

Employees

As of Dec. 31, 2019, Xcel Energy had 11,273 full-time employees and 44 part-time employees, of which 5,091 were covered under CBAs.

	Employees Covered by CBAs	Total Employees
NSP-Minnesota	2,036	3,203
NSP-Wisconsin	392	538
PSCo	1,884	2,369
SPS	779	1,158
XES	—	4,005
Total	5,091	11,273

Information about our Executive Officers [(a)]

Name	Age [(b)]	Current and Recent Positions	Time in Position
Ben Fowke [(c)]	61	Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2011 — Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	January 2015 — Present
Brett C. Carter	53	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company	October 2015 — May 2018
		Senior Vice President and Chief Operating Officer, Bank of America	March 2015 — October 2015
		Senior Vice President and Chief Distribution Officer, Duke Energy Co., an electric power company	February 2013 — March 2015
Christopher B. Clark	53	President and Director, NSP-Minnesota	January 2015 — Present
David L. Eves [(d)]	61	Executive Vice President and Group President, Utilities, Xcel Energy Inc.	March 2018 — Present
		President and Director, PSCo	January 2015 — February 2018
Darla Figoli	57	Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President, Human Resources and Employee Services, Xcel Energy Inc.	May 2015 — May 2018
		Vice President, Human Resources, Xcel Energy Inc.	February 2010 — May 2015
Robert C. Frenzel [(c)]	49	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 — Present
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. [(e)]	February 2012 — April 2016
David T. Hudson	59	President and Director, SPS	January 2015 — Present
Alice Jackson	41	President and Director, PSCo	May 2018 — Present
		Area Vice President, Strategic Revenue Initiatives, Xcel Energy Services Inc.	November 2016 — May 2018
		Regional Vice President, Rates and Regulatory Affairs, PSCo	November 2013 — November 2016
Kent T. Larson [(f)]	60	Executive Vice President and Group President Operations, Xcel Energy Inc.	January 2015 — Present
Timothy O'Connor [(g)]	60	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc.	February 2013 — Present
Judy M. Poferl [(h)]	60	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc.	January 2015 — Present
Jeffrey S. Savage	48	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 — Present
Mark E. Stoering	59	President and Director, NSP-Wisconsin	January 2015 — Present
Scott M. Wilensky	63	Executive Vice President, General Counsel, Xcel Energy Inc.	January 2015 — Present

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

(b) Ages as of Dec. 31, 2019.

(c) Effective March 31, 2020, Mr. Fowke will cease to serve as President and Mr. Frenzel will become President and Chief Operating Officer of Xcel Energy Inc. At the same time, Brian J. Van Abel will become Executive Vice President, Chief Financial Officer of Xcel Energy Inc.

(d) Effective May 1, 2020, Mr. Eves will be retiring from the Company after retiring from his executive officer positions effective March 30, 2020.

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

(f) Effective May 31, 2020, Mr. Larson will be leaving the Company after ceasing to serve in his executive officer positions effective March 30, 2020.

(g) Effective March 31, 2020, Mr. O'Connor will become Executive Vice President, Chief Generation Officer.

(h) Effective March 31, 2020, Ms. Poferl will be retiring from the Company. Frank Prager has been elected to serve with the title of Senior Vice President, Strategy and Planning and External Affairs effective March 1, 2020.

ITEM 1A — RISK FACTORS

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

Oversight of Risk and Related Processes

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

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

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

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

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

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

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

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

Risks Associated with Our Business

Operational Risks

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

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages. These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses. We maintain insurance against most, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows.

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

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

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

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

In addition, the long-term nature of both our planning and our asset lives are subject to risk. The electric utility sector is undergoing a period of significant change. For example, increases in energy efficiency, wider adoption of lower cost renewable generation, distributed generation and shifts away from coal generation to decrease carbon emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, as well as stranded costs if we are not able to fully recover costs and investments.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure, which increases exposure to technology obsolescence. Evolving stakeholder preference for lower emission generation sources may pressure our investments in natural gas generation and delivery.

The magnitude and timing of resource additions and changes in customer demand may not coincide while customer preference for resource generation may change, which introduces further uncertainty into long-term planning. Additionally, multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We are subject to longer-term availability of 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.

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

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

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

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

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

Certain specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets. The Company's business strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees is high in the areas of business operations. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. We have seen a tightening of supply for engineers and skilled laborers in certain markets and are implementing plans to retain these employees. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

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

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

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

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

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

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

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

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota and may be subject to risks associated with NSP-Minnesota's nuclear generation.

Financial Risks

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

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

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

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

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

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

In a continued low interest rate environment, there has been increased downward pressure on allowed ROE. Conversely, higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers.

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

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

We cannot be assured that our current ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, significantly lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require 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. Capital markets are global and impacted by issues and events throughout the world. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

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

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in 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 may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

The Company may at times have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as CAISO, SPP, PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants. We have additional indirect credit exposure to financial institutions in the form of letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

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

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high numbers of retirements or employees leaving would trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

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

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

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

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

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

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

Federal tax law may significantly impact our business.

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

Macroeconomic Risks

Economic conditions impact our business.

Xcel Energy's operations are affected by local, national and worldwide economic conditions, which correlates to customers/sales growth(decline). Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills which could lead to additional bad debt expense.

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

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

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

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

We also face the risks of possible loss of business due to significant events such as severe storm, severe temperature extremes, wildfires (particularly in Colorado), widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force within our operating systems (or on a neighboring system).

The recent coronavirus outbreak in China is an example of how major catastrophic events throughout the world may disrupt our business. While we are a domestic company, the Company participates in a global supply chain, which includes materials and components that are sourced from China. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to reliably serve our customers.

Disruption due to events such as those noted above could result in a significant decrease in revenues and additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

Xcel Energy participates in biennial grid security and emergency response exercises (GridEx). These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

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

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

The Company's generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Xcel Energy's generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a 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. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

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

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

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

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

Public Policy Risks

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

Legislative and regulatory responses related to climate change and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs.

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

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

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

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties.

In the event of serious incidents, these agencies have become more active in pursuing penalties. Certain states additionally have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Environmental Risks

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

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

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

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or the O&M costs incurred to comply with the requirements.

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

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

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

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

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

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

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

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

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511	
Sherco-Becker, MN				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	517	(b)
Monticello, MN, 1 Unit	Nuclear	1971	617	
PI-Welch, MN				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Various locations, 4 Units	Wood/Refuse	Various	36	(c)
Combustion Turbine:				
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327	
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	494	
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	453	
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530	
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454	
Various locations, 7 Units	Natural Gas	Various	10	
Wind:				
Border-Rolette County, ND, 75 Units	Wind	2015	148	(d)
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190	(d)
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150	(d)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99	(d)
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99	(d)
Nobles-Nobles County, MN, 134 Units	Wind	2010	197	(d)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(d)
		Total	7,712	

(a) Summer 2019 net dependable capacity.
(b) Based on NSP-Minnesota's ownership of 59%.
(c) Refuse-derived fuel is made from municipal solid waste.
(d) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
Bay Front-Ashland, WI, 2 Units	Coal/Wood/Natural Gas	1948 - 1956	41	
French Island-La Crosse, WI, 2 Units	Wood/Refuse	1940 - 1948	16	(b)
Combustion Turbine:				
French Island-La Crosse, WI, 2 Units	Oil	1974	122	
Wheaton-Eau Claire, WI, 5 Units	Natural Gas/Oil	1973	234	
Hydro:				
Various locations, 63 Units	Hydro	Various	135	
		Total	548	

(a) Summer 2019 net dependable capacity.
(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
Comanche-Pueblo, CO [(b)]				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(c)
Craig-Craig, CO, 2 Units [(d)]	Coal	1979 - 1980	82	(e)
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233	(f)
Pawnee-Brush, CO, 1 Unit	Coal	1981	505	
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310	
Combustion Turbine:				
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264	
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576	
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	968	
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	171	
Hydro:				
Cabin Creek-Georgetown, CO				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 8 Units	Hydro	Various	25	
Wind:				
Rush Creek, CO, 300 units	Wind	2018	582	(g)
		Total	5,666	

(a) Summer 2019 net dependable capacity.
(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.
(c) Based on PSCo's ownership of 67%.
(d) Craig Unit 1 is expected to be retired early in 2025.
(e) Based on PSCo's ownership of 10%.
(f) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.
(g) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit	Fuel	Installed	MW (a)
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	189
Harrington-Amarillo, TX, 3 Units	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	460 (b)
		Total	4,804

(a) Summer 2019 net dependable capacity.

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

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2019:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	13,133	3,337	5,036	9,566
230 KV	2,203	—	12,108	9,784
161 KV	673	1,821	—	—
138 KV	—	—	92	—
115 KV	8,045	1,815	5,055	14,662
Less than 115 KV	86,743	32,816	79,740	26,216

Electric utility transmission and distribution substations at Dec. 31, 2019:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	346	204	233	452

Natural gas utility mains at Dec. 31, 2019:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	86	3	2,057	20	11
Distribution	10,518	2,473	22,633	—	—

ITEM 3 — LEGAL PROCEEDINGS

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 12 to the consolidated financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

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

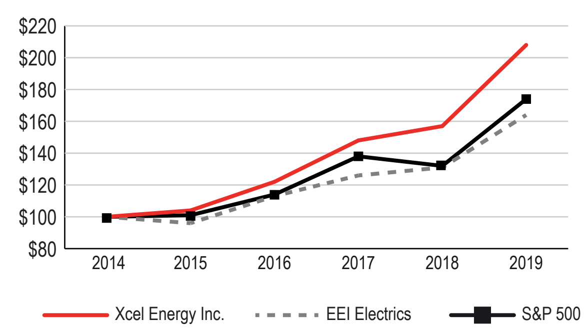
Stock Data

Xcel Energy Inc.'s common stock was listed on the New York Stock Exchange (NYSE) in 2017, but moved to the Nasdaq Global Select Market (Nasdaq) in 2018. The trading symbol is XEL. The number of common stockholders of record as of Feb. 19, 2020 was approximately 54,543.

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

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 40 companies at year-end and is a broad measure of industry performance.

Comparison of Five Year Cumulative Total Return*



* $100 invested on Dec. 31, 2014 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance under Equity Compensation Plans is contained in Xcel Energy's Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2019, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6 — SELECTED FINANCIAL DATA

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

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2019	2018	2017	2016	2015
Operating revenues	$ 11,529	$ 11,537	$ 11,404	$ 11,107	$ 11,024
Operating expenses [(a)]	9,425	9,572	9,181	8,867	9,024
Net income	1,372	1,261	1,148	1,123	984
Earnings available to common shareholders	1,372	1,261	1,148	1,123	984
Diluted earnings per common share	2.64	2.47	2.25	2.21	1.94
Financial information					
Dividends declared per common share	1.62	1.52	1.44	1.36	1.28
Total assets [(b) (c)]	50,448	45,987	43,030	41,155	38,821
Long-term debt [(c) (d)]	17,407	15,803	14,520	14,195	12,399

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

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

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

(d) As a result of adopting *Leases, Topic 842,* finance lease obligations of $77 million are included in other noncurrent liabilities on the consolidated balance sheet at Dec. 31, 2019. These obligations were included in long-term debt prior to 2019.

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

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing ROE, electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

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

Ongoing ROE

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

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

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

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

We use these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the years ended Dec. 31, 2019 and Dec. 31, 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

	2019	2018
Diluted Earnings (Loss) Per Share	GAAP and Ongoing Diluted EPS	GAAP and Ongoing Diluted EPS
PSCo	$ 1.11	$ 1.08
NSP-Minnesota	1.04	0.96
SPS	0.51	0.42
NSP-Wisconsin	0.15	0.19
Equity earnings of unconsolidated subsidiaries [(a)]	0.05	0.04
Regulated utility [(b)]	2.86	2.69
Xcel Energy Inc. and other	(0.22)	(0.22)
Total [(b)]	$ 2.64	$ 2.47

(a) Includes income taxes.

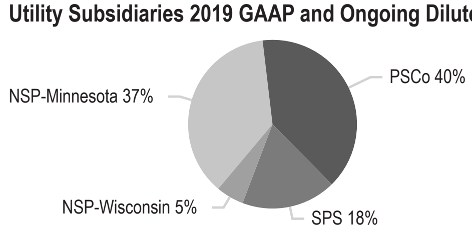
(b) Amounts may not add due to rounding.

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

2019 Comparison with 2018

Xcel Energy — GAAP and ongoing earnings increased $0.17 per share. Earnings increased as a result of higher electric margins primarily due to non-fuel riders and regulatory rate outcomes, higher natural gas margins and lower O&M expenses, primarily offset by lower AFUDC, increased depreciation and interest expenses.

Utility Subsidiaries 2019 GAAP and Ongoing Diluted EPS



PSCo — Earnings increased $0.03 per share for 2019, reflecting higher electric margin due primarily to capital riders and increased natural gas margin attributable to capital riders, weather and sales growth, partially offset by lower AFUDC driven by the Rush Creek wind project that was placed in service in 2018 and higher depreciation, interest and O&M.

NSP-Minnesota — Earnings increased $0.08 per share for 2019, reflecting higher electric margin resulting from regulatory rate outcomes and capital riders and lower O&M, partially offset by increased depreciation.

SPS — Earnings increased $0.09 per share, reflecting higher electric margin attributable to purchased capacity costs, regulatory rate outcomes and demand revenue and higher AFUDC, partially offset by increased interest and depreciation.

NSP-Wisconsin — Earnings decreased $0.04 per share, reflecting lower electric margin, primarily related to sales decline and the impact of unfavorable weather, higher depreciation and lower AFUDC.

Xcel Energy Inc. and other — Xcel Energy Inc. and other primarily includes financing costs at the holding company.

Changes in Diluted EPS

Components significantly contributing to changes in EPS:

2019 vs. 2018	
Diluted Earnings (Loss) Per Share	**Dec. 31**
GAAP and ongoing diluted EPS - 2018	**$ 2.47**
Components of change — 2019 vs. 2018	
Higher electric margins	0.29
Lower ETR [(a)]	0.15
Higher natural gas margins	0.08
Lower O&M	0.02
Higher depreciation and amortization	(0.18)
Higher interest	(0.11)
Lower AFUDC	(0.08)
GAAP and ongoing diluted EPS — 2019	**$ 2.64**

(a) Includes PTCs and timing of tax reform regulatory decisions, which are primarily offset in electric margin.

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

	2019	2018
ROE	GAAP and Ongoing ROE	GAAP and Ongoing ROE
PSCo	8.69%	9.10%
NSP-Minnesota	9.31	8.91
SPS	9.71	9.14
NSP-Wisconsin	8.27	10.77
Operating Companies	9.06	9.14
Xcel Energy	10.78	10.65

Statement of Income Analysis

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

Estimated Impact of Temperature Changes on Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances, the amount of natural gas or electricity historically used per degree of temperature and excludes any incremental related operating expenses that could result due to storm activity or vegetation management requirements. As a result, weather deviations from normal levels can affect Xcel Energy's financial performance.

Degree-day or THI data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. CDD is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

Percentage increase (decrease) in normal and actual HDD, CDD and THI:

	2019 vs. Normal	2018 vs. Normal	2019 vs. 2018
HDD	10.4%	2.2%	6.8%
CDD	5.4	26.7	(15.5)
THI	(8.8)	37.3	(33.2)

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

	2019 vs. Normal	2018 vs. Normal	2019 vs. 2018
Retail electric	$ 0.040	$ 0.114	$ (0.074)
Firm natural gas	0.027	0.007	0.020
Total (excluding decoupling)	$ 0.067	$ 0.121	$ (0.054)
Decoupling — Minnesota electric	—	(0.051)	0.051
Total (adjusted for recovery from decoupling)	$ 0.067	$ 0.070	$ (0.003)

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

	2019 vs. 2018				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	0.1%	(3.5)%	0.3%	(1.8)%	(1.5)%
Electric C&I	(0.6)	(4.0)	3.5	(3.2)	(1.1)
Total retail electric sales	(0.3)	(3.9)	2.8	(2.8)	(1.2)
Firm natural gas sales	12.9	3.6	N/A	(2.0)	8.8

	2019 vs. 2018				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(0.1)%	0.1%	1.9%	1.1%	0.4%
Electric C&I	(0.6)	(3.0)	3.8	(2.6)	(0.5)
Total retail electric sales	(0.3)	(2.1)	3.4	(1.6)	(0.3)
Firm natural gas sales	4.1	1.1	N/A	(2.5)	2.7

Weather-normalized 2019 Electric Sales Growth (Decline)

- PSCo — Residential sales declined due to lower use per customer, partially offset by an increased number of customers. The decline in C&I was mainly due to lower use per customer, primarily led by customers in the food products and service industries, partially offset by growth in the metal mining and fabricated metal and industries. The decrease in customer use was partially offset by an increase in the number of C&I customers;
- NSP-Minnesota — Flat residential sales reflect lower use per customer offset by customer additions. The decline in C&I sales was a result of customer growth being offset by lower use per customer, and certain customers moving to co-generation. Decreased sales to C&I customers were driven by the energy and manufacturing sectors;
- SPS — Residential sales grew largely due to an increase in customers and higher use per customer. C&I sales grew based on higher use per small C&I customer and an overall increase in the number of C&I customers. In addition, the increase in C&I sales was driven by the oil and natural gas industry in the Southeastern New Mexico, Permian Basin area; and
- NSP-Wisconsin — Residential sales growth was primarily attributable to customer additions and more use per customer. The decline in C&I sales was largely due to lower use per customer and decreased sales to the frac sand mining, food and manufacturing sectors, which was partially offset by customer additions.

Weather-normalized 2019 Natural Gas Sales Growth

- Overall natural gas sales reflect an increase in the number of customers combined with higher customer use, particularly C&I at PSCo. This was partially offset by a decline in C&I sales at NSP-Wisconsin, driven by the frac sand mining industry.

Weather-normalized sales for 2020 are projected to increase ~1% over 2019 levels for retail electric and natural gas customers, including the impact of leap year.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs generated in a particular period.

Electric Margin

(Millions of Dollars)	2019 vs. 2018
Non-fuel riders [(a)]	$ 107
Regulatory rate outcomes (Minnesota, New Mexico, North and South Dakota)	95
Implementation of lease accounting standard (offset in interest expense and amortization)	22
Purchased capacity costs	22
Demand revenue	20
Wholesale transmission revenue (net)	11
Timing of tax reform regulatory decisions (offset in income tax and amortization)	(37)
Estimated impact of weather (net of Minnesota decoupling)	(25)
Firm wholesale generation	(20)
Sales declines (excluding weather impact)	(18)
Other (net)	23
Total increase in electric margin	$ 200

(a) Includes approximately $60 million of additional PTC benefit (grossed-up for tax) as compared to 2018, which are credited to customers through various regulatory mechanisms.

Natural Gas Margin

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

Natural Gas Margin

(Millions of Dollars)		2019 vs. 2018
Infrastructure and integrity riders	$	19
Estimated impact of weather		14
Transport sales		7
Retail sales growth		7
Other (net)		7
Total increase in natural gas margin	$	54

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $14 million, or 0.6%, for 2019. Significant changes are summarized below:

(Millions of Dollars)		2019 vs. 2018
Plant generation	$	(20)
Nuclear plant operations and amortization		(8)
Transmission		(7)
Distribution		16
Other (net)		5
Total decrease in O&M expenses	$	(14)

- Plant generation, transmission and distribution costs were lower due to timing of maintenance activities;
- Nuclear plant operations and amortization were lower largely reflecting improved operating efficiencies and reduced refueling outage costs; and
- Distribution expenses in 2019 were higher than 2018 due to storms, labor and overtime incurred primarily in the first six months of 2019.

Depreciation and Amortization — Depreciation and amortization increased $123 million, or 7%, for 2019. The increase was primarily driven by the Rush Creek, Hale, Foxtail and Lake Benton wind farms going into service, natural gas and distribution/transmission replacements, and various software solutions. These increases were partially offset by higher levels of accelerated amortization of PSCo's prepaid pension asset in 2018.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $13 million, or 2.3%, for 2019. The increase was primarily due to higher property taxes in Colorado and Minnesota (net of deferred amounts).

AFUDC, Equity and Debt — AFUDC decreased $42 million for 2019. The decrease was primarily due to the Rush Creek wind project being placed in-service in 2018, partially offset by the Hale wind project, which went into service in June 2019, and other capital investments.

Interest Charges — Interest charges increased $73 million, or 10.4%, for 2019. The increase was primarily due to higher debt levels to fund capital investments, changes in short-term interest rates and implementation of lease accounting standard (offset in electric margin).

Income Taxes — Income taxes decreased $53 million for 2019, primarily driven by an increase in wind PTCs. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. These were partially offset by higher pretax earnings in 2019 and ITCs in 2018. The ETR was 8.5% for 2019 compared with 12.6% for the same period in 2018, largely due to the adjustments above.

Xcel Energy Inc. and Other Results

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

	Contribution (Millions of Dollars)			
	2019		2018	
Xcel Energy Inc. financing costs	$	(128)	$	(110)
Eloigne [(a)]		1		—
Xcel Energy Inc. taxes and other results		12		(5)
Total Xcel Energy Inc. and other costs	$	(115)	$	(115)

	Contribution (Diluted Earnings (Loss) Per Share)			
	2019		2018	
Xcel Energy Inc. financing costs	$	(0.21)	$	(0.21)
Eloigne [(a)]		—		—
Xcel Energy Inc. taxes and other results		(0.01)		(0.01)
Total Xcel Energy Inc. and other costs	$	(0.22)	$	(0.22)

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

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

2018 Comparison with 2017

A discussion of changes in Xcel Energy's results of operations and liquidity and capital resources from the year ended Dec. 31, 2017 to Dec. 31, 2018 can be found in Part II, "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year 2018, which was filed with the SEC on Feb. 22, 2019. However, such discussion is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Public Utility Regulation

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

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

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

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

NSP-Minnesota

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

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

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

Recovery Mechanisms

Mechanism	Additional Information
CIP Rider [(a)]	Recovers costs of conservation and DSM programs.
EIR	Recovers costs of environmental improvement projects.
RDF	Allocates money collected from customers to support research and development of emerging renewable energy projects and technologies.
RES	Recovers cost of renewable generation in Minnesota.
RER	Recovers the cost of renewable generation in North Dakota.
SEP	Recovers costs related to various energy policies approved by the Minnesota legislature.
TCR	Recovers costs for investments in electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation and incremental property taxes in South Dakota.
FCA [(b)]	Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. MISO costs are generally recovered through either the FCA or base rates.
PGA	Provides for prospective monthly rate adjustments for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actuals costs.
GUIC Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including: funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs.

(a) Minnesota state law requires NSP-Minnesota to invest 2% of its state electric revenues and 0.5% of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism.

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

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					MPUC
2018 TCR	Electric	$98	November 2017	Received	In November 2019, the MPUC issued an order setting an ROE of 9.06% and recovery of 2017-2018 expenses related to advanced grid investments.
2020 TCR	Electric	$82	November 2019	Pending	In November 2019, NSP-Minnesota filed the 2020 TCR Rider. The filing included an ROE of 9.06%. Timing of an MPUC ruling is uncertain.
2019 GUIC	Natural Gas	$29	November 2018	Pending	In November 2018, NSP-Minnesota filed the 2019 GUIC Rider with the MPUC. The filing included an ROE of 10.25%. Timing of an MPUC ruling is uncertain.
2020 GUIC	Natural Gas	$21	November 2019	Pending	In November 2019, NSP-Minnesota filed the 2020 GUIC Rider with the MPUC. The filing included an ROE of 9.04%. Timing of an MPUC ruling is uncertain.
2018 RES	Electric	$23	November 2017	Received	In November 2019, the MPUC approved an order setting an ROE of 9.06%.
2020 RES	Electric	$102	November 2019	Pending	In November 2019, NSP-Minnesota filed the 2020 RES Rider with the MPUC. The requested amount includes a true up for the 2019 rider of $38 million and the 2020 requested amount of $64 million. The filing included an ROE of 9.06%. Timing of an MPUC ruling is uncertain.

Minnesota Electric Rate Case and Alternative Petition — In November 2019, NSP-Minnesota filed a three-year electric rate case with the MPUC. The proposed electric rates reflect a three-year increase in revenues of approximately $201.4 million (6.5%) in 2020, with subsequent incremental increases of $146.4 million (4.8%) in 2021 and $118.3 million (3.9%) in 2022. The rate case is based on a requested ROE of 10.2%, a 52.5% equity ratio, an average electric rate base of $9.0 billion for 2020, $9.3 billion for 2021 and $9.8 billion for 2022.

In addition, NSP-Minnesota requested interim rates, subject to refund, of $122.0 million to be implemented in January 2020 and an incremental $144.0 million to be implemented in January 2021.

NSP-Minnesota also filed a stay-out petition, in which NSP-Minnesota would withdraw its electric rate case and refrain from filing another rate case for one year if the MPUC were to approve an extension of true-up mechanisms for sales, capital and property taxes. NSP-Minnesota also requested that the MPUC delay any increase to the Nuclear Decommissioning Trust annual accrual until 2021.

In December 2019, the MPUC verbally approved the stay-out petition including extension of the sales, capital and property tax true-up mechanisms and the delay of any increase to the Nuclear Decommissioning Trust annual accrual until Jan. 1, 2021.

MEC Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company (a subsidiary of Southern Company) to purchase MEC, a 760 MW natural gas combined cycle facility, for approximately $650 million.

In September 2019, the MPUC denied NSP-Minnesota's request to purchase MEC as a rate base asset. In January 2020, the MPUC approved Xcel Energy's plan to acquire MEC as a non-regulated investment and step into the terms of the existing PPAs with NSP-Minnesota. A newly formed non-regulated subsidiary of Xcel Energy completed the transaction to purchase MEC on Jan. 17, 2020.

Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034. The plan would result in an 80% carbon reduction by 2030 (from 2005) and puts NSP-Minnesota on a path to achieving its vision of being 100% carbon-free by 2050. The preferred plan includes the following:

- Extends the life of the Monticello nuclear plant from 2030 to 2040;
- Continues to run PI through current end of life (2033 and 2034);
- Includes the MEC acquisition and construction of the Sherco combined cycle natural gas plant;
- Includes the early retirement of the King coal plant (511 MW) in 2028 and the Sherco 3 coal plant (517 MW) in 2030;
- Adds approximately 1,700 MW of firm peaking (combustion turbine, pumped hydro, battery storage, demand response, etc.);
- Adds approximately 1,200 MW of wind replacement; and
- Adds approximately 4,000 MW of solar.

Intervening parties will provide recommendations and comments on the resource plan. Following the MPUC's denial of its request to purchase MEC, NSP-Minnesota will provide updates to remove its ownership of MEC from the preferred plan. The MPUC required NSP-Minnesota to update its filing to address issues related to its decision on MEC, including certain new modeling scenarios. An updated filing is required by April 1, 2020. The MPUC is anticipated to make a final decision on the resource plan in the first half of 2021.

Jeffers Wind and Community Wind North Repowering Acquisition — In October 2019, the MPUC approved NSP-Minnesota's request to acquire the Jeffers and Community Wind North wind facilities in western Minnesota from Longroad Energy. The wind farms will have approximately 70 MW of capacity after being repowered. The repowering is expected to be completed by December 2020 and qualify for the full PTC. The $135 million asset acquisition is projected to provide customer savings of approximately $7 million over the life of the facilities.

Mower Wind Facility — In August 2019, NSP-Minnesota filed a petition with the MPUC to acquire the Mower wind facility from affiliates of NextEra Energy, Inc. for an undisclosed amount. The Mower facility is located in southeastern Minnesota and is currently contracted under a PPA with NSP-Minnesota through 2026. Mower is expected to continue to have approximately 99 MW of capacity following a planned repowering. The acquisition would occur after repowering, which is expected to be complete in 2020 and qualify for the full PTC. NSP-Minnesota will need approval from both the MPUC and FERC to complete the transaction. NSP-Minnesota filed reply comments addressing the DOC's concerns with the transaction in February 2020.Timing of MPUC and FERC decisions are uncertain.

Purchased Power Arrangements and Transmission Service Provider

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

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

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

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

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from Mankato to Winnebago, Minnesota.

The project was estimated to cost $108 million and projected to be in-service by the end of 2021. It was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss.

In June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal in July 2018. In September 2019, the estimate was updated to approximately $140 million, due to various changes in build plans. In October 2019, oral arguments were held with the Eighth Circuit Court of Appeals. A decision is expected in the first or second quarter of 2020.

Nuclear Power Operations and Waste Disposal

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

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

Low-Level Waste Disposal — Low level waste disposal from Monticello and PI is disposed at the Clive facility located in Utah and the Waste Control Specialists facility in Texas. NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives if of-site low-level waste disposal facilities become unavailable.

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

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

Wholesale and Commodity Marketing Operations

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

NSP-Minnesota also engages in trading activity unrelated to hedging. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

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

Recovery Mechanisms

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

(a) NSP-Wisconsin's electric fuel costs were lower than authorized in rates and outside the 2% annual tolerance band in 2019. Under the fuel cost recovery rules, NSP-Wisconsin retained the $3.3 million of over-recovered fuel costs (amounts within annual tolerance band) and deferred $9.7 million (amounts in excess of annual tolerance band) as a regulatory liability. NSP-Wisconsin plans to file a reconciliation of 2019 fuel costs with the PSCW by March 2020.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					PSCW
Rate Case	Electric & Natural Gas	N/A	May 2019	Received	In May 2019, NSP-Wisconsin filed an application with the PSCW seeking no change to base electric rates through Dec. 31, 2021; and a $3.2 million (4.6%) decrease to base natural gas rates, effective Jan. 1, 2020, and no additional changes to base natural gas rates through Dec. 31, 2021. The settlement is based on an ROE of 10.0% and an equity ratio of 52.5%. In September 2019, the PSCW issued an interim order approving the settlement agreement as filed with one minor modification, to remove the deferral of pension settlement accounting costs for 2021. A final order was received in December 2019.

Purchased Power and Transmission Services

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

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

Wholesale and Commodity Marketing Operations

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

PSCo

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
CPUC	Retail rates, accounts, services, issuance of securities and other aspects of electric and natural gas operations. Pipeline safety compliance.
FERC	Wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. Wholesale electric sales at cost-based prices to customers inside PSCo's balancing authority area and at market-based prices to customers outside PSCo's balancing authority area. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.
RTO	PSCo is not presently a member of an RTO and does not operate within an RTO energy market. However, PSCo does make certain sales to other RTO's, including SPP and participates in a joint dispatch agreement with neighboring utilities.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
ECA	Recovers fuel and purchased energy costs. Short-term sales margins are shared with customers through the ECA. The ECA is revised quarterly.
PCCA	Recovers purchased capacity payments.
SCA	Recovers difference between actual fuel costs and costs recovered under steam service rates. The SCA rate is revised quarterly.
DSMCA	Recovers DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
RESA	Recovers the incremental costs of compliance with the RES with a maximum of 2% of the customer's bill.
WCA	Recovers costs for customers who choose renewable resources.
TCA	Recovers costs for transmission investment outside of rate cases.
CACJA	Recovers costs associated with the CACJA.
FCA	PSCo recovers fuel and purchased energy costs from wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay production costs through a forecasted formula rate subject to true-up.
GCA	Recovers costs of purchased natural gas and transportation and is revised quarterly to allow for changes in natural gas rates.
PSIA	Recovers costs for transmission and distribution pipeline integrity management programs.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					CPUC
Rate Case	Steam	$7	January 2019	Received	In September 2019, the CPUC approved PSCo's Settlement Agreement with CPUC Staff and the City of Denver. The settlement reflects an ROE of 9.67% for AFUDC purposes, an equity ratio of 56.04% and utilization of tax reform benefits. The first stepped increase went into effect Oct. 1, 2019, with full rates effective Oct. 1, 2020.
Rate Case Appeal	Natural Gas	N/A	April 2019	Pending	In April 2019, PSCo filed an appeal seeking judicial review of the CPUC's prior ruling regarding PSCo's last natural gas rate case (approved in December 2018). Appeal requests review of the following: denial of a return on the prepaid pension and retiree medical assets; the use of a capital structure that is not based on the actual historical test year level; and the use of an average rate base methodology rather than a year-end rate base methodology. Timeline on a final ruling is unknown.
DSM Incentive	Electric & Natural Gas	$12	April 2019	Received	PSCo earned an electric and natural gas DSM incentive of $9 million and $3 million, respectively, for achieving its 2018 savings goals.

PSCo — Electric Rate Case — In October 2019, PSCo filed rebuttal testimony with the CPUC requesting a net rate increase of $108 million. This is based on a $353 million increase offset by $245 million of previously authorized costs currently recovered through various rider mechanisms. The request was based on a ROE of 10.20%, an equity ratio of 55.61% and a current test year, which includes certain forecasted plant additions through December 2019.

In December 2019, the CPUC held deliberations and on Feb. 11, 2020 issued a written decision approving a current test year ended Aug. 31, 2019, a 9.3% ROE, an equity ratio of 55.61%, implementation of decoupling in 2020 and other items. This resulted in an estimated $35 million net base rate revenue increase.

Revenue Request (Millions of Dollars)	2020
Company filed rebuttal	$ 353
ROE	(55)
Impact of change in test year	(17)
Property tax expense	15
Rate base adjustments	(11)
Capital structure	(5)
Total proposed revenue change	280
Estimated impact of previously authorized costs (existing riders)	245
Net revenue change	**$ 35**

Final rates are expected to be implemented in February 2020. PSCo currently intends to file an application for rehearing/reconsideration in the first quarter of 2020.

PSCo — Gas Rate Case — On Feb. 5, 2020, PSCo filed a request with the CPUC seeking a net increase to retail gas rates of $127 million, reflecting a $145 million increase in base rate revenue, which is partially offset by $18 million previously authorized through the PSIA rider mechanism. The request is based on a test year that incorporates actual capital and expenses as of Sept. 30, 2019, adjusted for known and measurable differences for the 12-month period ended Sept. 30, 2020, a 9.95% ROE and an equity ratio of 55.81%. Proposed effective date is Nov. 1, 2020.

Revenue Request (Millions of Dollars)	2020
Capital additions (through Sept. 30, 2019)	$ 62
Forecasted capital additions (through Sept. 30, 2020)	33
Sales growth (includes amounts forecasted through Sept. 30, 2020)	(29)
Operations and maintenance, amortization and other expenses	29
Property tax expense	19
Cost of capital	8
Updated depreciation rates	5
Net increase to revenue	**127**
Previously authorized costs:	
Transfer PSIA rider costs to base rates	18
Total base request	**$ 145**
Expected year-end rate base	**$ 2,236**

The request reflects $1.3 billion of capital additions since the 2016 test year used to set current rates. Capital investments are made to maintain the safety and reliability of the natural gas system, along with investments to connect new customers and perform mandated infrastructure relocation work.

Timing of a CPUC ruling is expected in the second half of 2020.

Resource Plan

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

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

PSCo's investment is expected to be approximately $1 billion, including transmission to support the increase in renewable generation.

CPCNs were granted by the CPUC for the Shortgrass Substation in February 2019, and for the 500 MW Cheyenne Ridge wind farm and 345 KV generation tie line in April 2019.

A CPCN for the acquisitions of the Valmont and Manchief natural gas generation facilities was filed in July 2019, and a settlement on those acquisitions was reached with CPUC Staff and the Colorado Office of Consumer Counsel in January 2020, pending a CPUC decision expected in approximately the second quarter of 2020.

A CPCN for voltage control facilities was also filed with the CPUC in December 2019, with another expected to follow in approximately the first quarter of 2020 for network transmission upgrades required for the CEP portfolio.

Purchased Power and Transmission Service Providers

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

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

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

Boulder Municipalization

In 2011, Boulder passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Subsequently, there have been various legal proceedings in multiple venues with jurisdiction over Boulder's plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility and the Colorado Court of Appeals ruled in PSCo's favor, vacating a lower court decision. In June 2018, the Colorado Supreme Court rejected Boulder's request to dismiss the case and remanded it to the Boulder District Court. The case was then settled in June 2019 after Boulder agreed to repeal the ordinance establishing the utility.

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position. The CPUC has approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings.

In the fourth quarter of 2018, the Boulder City Council also adopted an Ordinance authorizing Boulder to begin negotiations for the acquisition of certain property or to otherwise condemn that property after Feb. 1, 2019. In the first quarter of 2019, Boulder sent PSCo a notice of intent to acquire certain electric distribution assets. In the third quarter of 2019, Boulder filed its condemnation litigation, which was later dismissed by the Boulder District Court in September 2019 on the grounds that Boulder had not completed the pre-requisite CPUC process and filings. Boulder is currently appealing this order. In October 2019, the CPUC approved the subsequent filings regarding asset transfers outside of substations, reaffirmed its 2017 decision on assets outside of substations and closed the CPUC proceeding.

In December 2019, Boulder filed a new condemnation action despite its ongoing appeal of the last condemnation case. PSCo subsequently filed a motion to dismiss or stay the new condemnation action. In February 2020, Boulder filed an application under section 210 of the Federal Power Act asking FERC to order PSCo to interconnect its facilities with a future Boulder municipal utility under Boulder's preferred terms and conditions.

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

SPS

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

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

Recovery Mechanisms

Mechanism	Additional Information
DCRF	Recovers distribution costs not included in rates in Texas.
EECRF	Recovers costs for energy efficiency programs in Texas.
Energy Efficiency Rider	Recovers costs for energy efficiency programs in New Mexico.
FPPCAC	Adjusts monthly to recover actual fuel and purchased power costs in New Mexico. In October 2019, SPS filed an application to the NMPRC to approve SPS' continued use of its FPPCAC and for reconciliation of fuel costs for the period Sept. 1, 2015, through June 30, 2019, which will determine whether all fuel costs incurred are eligible for recovery. No procedural schedule has yet been established for this matter.
PCRF	Allows recovery of purchased power costs not included in Texas rates.
RPS	Recovers deferred costs for renewable energy programs in New Mexico.
TCRF	Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Fixed Fuel and Purchased Recovery Factor	Provides for the over- or under-recovery of energy expenses. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					SPS (NMPRC)
Rate Case	Electric	$51	July 2019	Pending	In July 2019, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $51 million. The rate request is based on an ROE of 10.35%, an equity ratio of 54.77%, a rate base of approximately $1.3 billion and a historic test year with rate base additions through Aug. 31, 2019. In December 2019, SPS revised its base rate increase request to approximately $47 million, based on an ROE of 10.10% and updated information. The request also included an increase of $14.6 million for accelerated depreciation including the early retirement of the Tolk Coal Plant in 2032. On Jan. 13, 2020, SPS and various parties filed an uncontested comprehensive stipulation. The stipulation includes a base rate revenue increase of $31 million, based on an ROE of 9.45% and an equity ratio of 54.77%. The stipulation also includes an acceleration of depreciation on the Tolk Coal Plant to reflect early retirement in 2037, which results in a total increase in depreciation expense of $8 million. The Signatories will not oppose the full application of depreciation rates associated with the 2032 retirement date in SPS' next base rate case. SPS anticipates final rates will go into effect in the second or third quarter of 2020.

SPS — Texas Electric Rate Case

In August 2019, SPS filed an electric rate case with the PUCT seeking an increase in retail electric base rates of approximately $141 million. The filing requests an ROE of 10.35%, a 54.65% equity ratio, a rate base of approximately $2.6 billion and is built on a 12 month period that ended June 30, 2019. In September 2019, SPS filed an update to the electric rate case and revised its requested increase to approximately $137 million.

On Feb. 10, 2020, the Alliance of Xcel Municipalities (AXM), Texas Industrial Energy Consumers (TIEC), Office of Public Utility Counsel (OPUC) and Department of Energy (DOE) filed testimony along with several other parties.

On Feb. 18, 2020, the PUCT Staff filed testimony that included certain adjustments and various ring-fencing measures.

Proposed modifications to SPS' request:

(Millions of Dollars)	Staff	AXM	OPUC	TIEC	DOE
SPS Direct Testimony	$ 137	$ 137	$ 137	$ 137	$ 137
Recommended base rate adjustments:					
ROE	(22)	(24)	(15)	(21)	(24)
Capital structure	(7)	(10)	—	(7)	(3)
Tolk/Harrington O&M disallowance	—	(7)	—	—	—
Distribution and Transmission Capital Disallowances [(a)]	(7)	—	—	—	—
Depreciation expense	(8)	(15)	(8)	(20)	—
Excess ADIT unprotected plant	—	—	(7)	—	—
Income Tax Expense Differences	(12)	—	—	—	—
Other, net	(6)	(6)	(1)	(1)	—
Total Adjustments	(62)	(62)	(31)	(49)	(27)
Total proposed revenue change	$ 75	$ 75	$ 106	$ 88	$ 110

Recommended Position	Staff	AXM	OPUC [(b)]	TIEC	DOE
ROE	9.1%	9.0%	—%	9.2%	9.0%
Equity Ratio	51.00%	50.00%	—%	51.00%	53.00%

(a) Staff recommends exclusion of approximately $134 million in transmission, distribution, and general plant in service in this rate case resulting in an approximate $7 million decrease to the revenue requirement.

(b) OPUC did not provide a recommendation for an ROE or equity ratio. For illustrative purposes an ROE of 9.5% was used.

The next steps in the procedural schedule are expected to be as follows:

- Rebuttal testimony — March 11, 2020; and
- Public hearing begins — March 30, 2020

A PUCT decision and implementation of final rates is anticipated in the third quarter of 2020.

Resource Plan

In December 2018, the NMPRC issued a final order accepting SPS' IRP.

SPS is forecasting a surplus capacity of 382 MW in 2028, but a capacity deficit of approximately 2,896 MW in 2038. SPS' optimal resource plan for the planning period incorporates the addition of wind, simple cycle combustion turbine generation, combined cycle energy and entering PPAs. Various factors may impact this IRP, which could potentially require updates to the action plan and will be the subject of future IRPs, including:

- New and revised environmental regulations;
- Impacts of variability due to participation in the SPP;
- Customer expectations;
- Technological advances;
- Groundwater aquifer depletion at SPS's Tolk Station;
- Aging generation fleet;
- Load growth and gas price variability;
- Changes to tax credits and incentives; and
- Changes to renewable portfolio standard acquisitions.

SPS is required to file an IRP in New Mexico every three years and will file its next IRP in July 2021.

Texas State ROFR

In May 2019, the Governor signed into law Senate Bill 1938, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. The Texas Attorney General has made a motion to dismiss the federal court complaint. A ruling on the dismissal motion is expected in the first quarter of 2020.

Purchased Power Arrangements and Transmission Service Providers

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

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

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

Natural Gas

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

Critical Accounting Policies and Estimates

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

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

Regulatory Accounting

Xcel Energy is subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. Our rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or other comprehensive income.

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

As of Dec. 31, 2019 and 2018, Xcel Energy recorded regulatory assets of $3.4 billion and $3.8 billion, respectively, and regulatory liabilities of $5.5 billion and $5.6 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction is no longer probable, Xcel Energy would be required to charge these assets to current net income or other comprehensive income. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets.

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

Income Tax Accruals

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

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

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

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized based on an evaluation of expected future taxable income. Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. We may adjust our unrecognized tax benefits and interest accruals as disputes with the IRS and state tax authorities are resolved, and as new developments occur. These adjustments may increase or decrease earnings.

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

Employee Benefits

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

At Dec. 31, 2019, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87%, which is consistent with the rate set in 2018. The rate of return used to measure postretirement health care costs is 4.50% at Dec. 31, 2019, which represents a 80 basis point decrease from 2018. Xcel Energy's pension investment strategy is based on plan-specific investments that seek to minimize investment and interest rate risk as a plan's funded status increases over time. This strategy results in a greater percentage of interest rate sensitive securities being allocated to plans with a higher funded status and a greater percentage of growth assets being allocated to plans having a lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 3.49% and postretirement health care obligations at 3.47% at Dec. 31, 2019. This represents a 82 basis point and 85 basis point decrease, respectively, from 2018. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

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

If Xcel Energy were to use alternative assumptions, a 1% change would result in the following impact on 2019 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (16)	$ 18
Discount rate [(a)]	(5)	9

(a) These costs include the effects of regulation.

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

As of Dec. 31, 2019, the initial medical trend cost claim assumptions for Pre-65 was 6.0% and Post-65 was 5.1%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

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

	Accumulated Postretirement Benefit Obligation		Service and Interest Components	
(Millions of Dollars)	**+1%**	**-1%**	**+1%**	**-1%**
Health care cost trend	$51	$(43)	$2	$(2)

Funding requirements in 2020 were $150 million and are expected to decline in the following years. Investment returns exceeded assumed levels in 2017 and 2019 and were below assumed levels in 2018.

The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20% per year. As differences between actual and expected investment returns are incorporated into the market-related value, amounts are recognized in pension cost over the expected average remaining years of service for active employees (approximately 12 years in 2019).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $104 million in 2020 and $90 million in 2021, while the actual pension costs were $115 million in 2019 and $141 million in 2018. The expected decrease in 2020 and future year costs is primarily due to the reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2017 - 2020:

- $150 million in January 2020;
- $154 million in 2019;
- $150 million in 2018; and
- $162 million in 2017.

Future amounts may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

Xcel Energy contributed $15 million, $11 million and $20 million during 2019, 2018 and 2017, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $10 million during 2020. Xcel Energy recovers employee benefits costs in its utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability;
- In 2018, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2018 pension settlement accounting expense;
- Regulatory Commissions in Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions;
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset; and
- In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction.

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

Nuclear Decommissioning

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

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2.1 billion in 2019 and $2.0 billion in 2018.

NSP-Minnesota obtains periodic independent cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. Estimates of future cash flows are highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning filing every three years. The filing covers all expenses for the decommissioning of the nuclear plants, including decontamination and removal of radioactive material.

The most recent triennial filing was approved by the MPUC in January 2019. This approval did not result in a change to the ARO liability. In December 2019, the MPUC ordered Xcel Energy to maintain the current accrual through 2020 to align with the approved one year stay out of the previously filed three-year electric rate case. Xcel Energy will evaluate the scenarios and potentially propose a new accrual starting in 2022 when it submits the next triennial filing in December 2020.

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

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

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

Escalation Rates — Escalation rates represent projected cost increases due to general inflation and increases in the cost of decommissioning activities. NSP-Minnesota used an escalation rate of 3.4% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on the weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

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

If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately 4% to 7% have been used to calculate the net present value of the expected future cash flows over time.

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

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

The Company continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2019.

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

Derivatives, Risk Management and Market Risk

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

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

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

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

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

Fair value of net commodity trading contracts as of Dec. 31, 2019:

	Futures / Forwards Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [(a)]	$ (1)	$ 2	$ 2	$ 3	$ 6
NSP-Minnesota [(b)]	2	(3)	(2)	(10)	(13)
PSCo [(b)]	(4)	(22)	(31)	—	(57)
	$ (3)	$ (23)	$ (31)	$ (7)	$ (64)

(a) Prices actively quoted or based on actively quoted prices.

(b) Prices based on models and other valuation methods.

	Options Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [(a)]	$ 4	$ 1	$ —	$ —	$ 5

(a) Prices based on models and other valuation methods.

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

(Millions of Dollars)	2019	2018
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 17	$ 16
Contracts realized or settled during the period	(22)	(10)
Commodity trading contract additions and changes during the period	(54)	11
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ (59)	$ 17

At Dec. 31, 2019, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $10 million, whereas a 10% decrease would decrease pretax income by approximately $10 million. At Dec. 31, 2018, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $16 million, whereas a 10% decrease would decrease pretax income by approximately $16 million.

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

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

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2019	$ 0.4	$ 3.0	$ 0.6	$ 0.8	$ 0.3
2018	4.8	6.0	0.6	5.6	0.1

In November 2018, management temporarily increased the VaR limit to accommodate a 10-year transaction. NSP-Minnesota systematically hedging the transaction and the consolidated VaR returned below $3 million in early January 2019.

Nuclear Fuel Supply — NSP-Minnesota has received all enriched nuclear material for 2019 and has contracted for approximately 51% of its 2020 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 29% of its average enriched nuclear material requirements from these sources. Alternate potential sources provide the flexibility to manage NSP-Minnesota's nuclear fuel supply. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

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

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately $6 million in 2019 and $10 million in 2018.

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

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

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

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

At Dec. 31, 2019, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $19 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $14 million. At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $14 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $3 million.

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

Fair Value Measurements

Xcel Energy uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value. The Company's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2019.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2019.

See Notes 10 and 11 to the consolidated financial statements for further information.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2019	2018	2017
Net cash provided by operating activities	$ 3,263	$ 3,122	$ 3,126

Net cash provided by operating activities increased by $141 million for 2019 as compared to 2018. Increase was primarily due to additional net income (excluding amounts related to non-cash operating activities (e.g., depreciation and amortization and deferred tax expenses)), partially offset by increased refunds associated with TCJA.

Net cash provided by operating activities decreased by $4 million for 2018 as compared to 2017. Change was primarily due to refunds associated with the TCJA and timing of certain electric and natural gas recovery mechanisms, partially offset by the change in net income.

(Millions of Dollars)	2019	2018	2017
Net cash used in investing activities	$ (4,343)	$ (3,986)	$ (3,296)

Net cash used in investing activities increased by $357 million for 2019 as compared to 2018. Increase was primarily attributable to additional capital expenditures, primarily for wind projects.

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

(Millions of Dollars)	2019	2018	2017
Net cash provided by financing activities	$ 1,181	$ 928	$ 168

Net cash provided by financing activities increased by $253 million for 2019 as compared to 2018. Increase was primarily attributable to higher proceeds from issuances of long-term debt and common stock (primarily due to the forward equity agreement settling in August 2019), partially offset by higher repayments of long-term debt and dividends paid.

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

Capital Requirements

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

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future.

Contractual obligations and other commercial commitments as of Dec. 31, 2019:

		Payments Due by Period			
(Millions of Dollars)	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**After 5 Years**
Long-term debt, principal and interest payments	$ 31,433	$ 1,422	$ 2,702	$ 2,514	$ 24,795
Finance lease obligations	271	14	26	24	207
Operating leases obligations [(a)]	2,116	262	520	469	865
Unconditional purchase obligations [(b)]	5,831	1,302	1,940	1,178	1,411
Other long-term obligations, including current portion	680	64	89	59	468
Other short-term obligations	442	442	—	—	—
Short-term debt	595	595	—	—	—
Total contractual cash obligations	$ 41,368	$ 4,101	$ 5,277	$ 4,244	$ 27,746

(a) Included in operating lease obligations are $236 million, $463 million, $422 million and $750 million, for the less than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

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

Capital Expenditures — Current estimated base capital expenditures:

	Capital Forecast					
(Millions of Dollars)	**2020**	**2021**	**2022**	**2023**	**2024**	**2020 - 2024 Total**
By Subsidiary						
NSP-Minnesota	$ 2,025	$ 1,580	$ 1,670	$ 1,800	$ 1,845	$ 8,920
PSCo	1,415	1,445	1,720	1,565	1,530	7,675
SPS	1,025	530	700	750	800	3,805
NSP-Wisconsin	250	320	345	350	425	1,690
Other [(a)]	(85)	(65)	10	10	10	(120)
Total capital expenditures	$ 4,630	$ 3,810	$ 4,445	$ 4,475	$ 4,610	$ 21,970

(a) Other category includes intercompany transfers for safe harbor wind turbines. The $650M non-regulated acquisition of MEC in 2020 is not included above.

	Capital Forecast					
(Millions of Dollars)	**2020**	**2021**	**2022**	**2023**	**2024**	**2020 - 2024 Total**
By Function						
Renewables	$ 1,760	$ 315	$ —	$ —	$ —	$ 2,075
Electric generation	480	595	580	780	1,000	3,435
Electric transmission	625	835	1,295	1,270	1,260	5,285
Electric distribution	885	1,140	1,415	1,470	1,350	6,260
Natural gas	520	450	600	560	640	2,770
Other	360	475	555	395	360	2,145
Total capital expenditures	$ 4,630	$ 3,810	$ 4,445	$ 4,475	$ 4,610	$ 21,970

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

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

Financing Capital Expenditures through 2024 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

Current estimated financing plans for 2020 - 2024:

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from operations [(a)]	$ 13,905
New debt [(b)]	6,665
Equity through the DRIP and benefit program	400
Equity through the at-the-market program	250
Equity through forward equity agreements [(c)]	750
Base capital expenditures 2020 - 2024	$ 21,970
Maturing Debt	$ 3,245

[(a)] Net of dividends and pension funding.

[(b)] Reflects a combination of short and long-term debt; net of refinancing.

[(c)] Equity forward issued in 2019, but has not yet settled; settlement expected by Dec. 31, 2020

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial condition, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2020, Xcel Energy announced a quarterly dividend of $0.43 per share, which represents an increase of 6.2%.

Xcel Energy's dividend policy balances the following:

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

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

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

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

Funded status and pension assumptions:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Fair value of pension assets	$ 3,184	$ 2,742
Projected pension obligation [(a)]	3,701	3,477
Funded status	$ (517)	$ (735)

[(a)] Excludes non-qualified plan of $39 million and $33 million at Dec. 31, 2019 and 2018, respectively.

Pension Assumptions	2019	2018
Discount rate	3.49%	4.31%
Expected long-term rate of return	6.87	6.87

Capital Sources

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

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

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

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

In addition, Xcel Energy Inc. borrowed $500 million under a 364-day term loan agreement that expires Dec. 1, 2020. Xcel Energy has an option to request an extension through Nov. 30, 2021.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2019
Borrowing limit	$ 3,600
Amount outstanding at period end	595
Average amount outstanding	663
Maximum amount outstanding	945
Weighted average interest rate, computed on a daily basis	2.40%
Weighted average interest rate at end of period	2.34

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Borrowing limit	$ 3,600	$ 3,250	$ 3,250
Amount outstanding at period end	595	1,038	814
Average amount outstanding	1,115	788	644
Maximum amount outstanding	1,780	1,349	1,247
Weighted average interest rate, computed on a daily basis	2.72%	2.34%	1.35%
Weighted average interest rate at end of period	2.34	2.97	1.90

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

As of Feb. 18, 2020, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility	Drawn [(a)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 759	$ 491	$ —	$ 491
PSCo	700	49	651	1	652
NSP-Minnesota	500	10	490	1	491
SPS	500	123	377	1	378
NSP-Wisconsin	150	62	88	—	88
Total	$ 3,100	$ 1,003	$ 2,097	$ 3	$ 2,100

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

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2019 and 2018, the Company had approximately 525 million shares and 514 million shares of common stock outstanding, respectively.

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

Planned Financing Activity — Xcel Energy's 2020 financing plans reflect the following:

- Xcel Energy Inc. — approximately $700 million of senior unsecured bonds and approximately $75 to $80 million of equity through the DRIP and benefit programs;
- NSP-Minnesota — approximately $550 million of first mortgage bonds;
- NSP-Wisconsin — approximately $100 million of first mortgage bonds
- PSCo — approximately $750 million of first mortgage bonds; and
- SPS — approximately $300 million of first mortgage bonds.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $459 million public offering of 9.4 million shares of common stock. In August 2019, we settled the forward equity agreements by physically delivering 9.4 million shares of common equity for cash proceeds of $453 million.

In November 2019, Xcel Energy Inc. entered into forward equity agreements for a $743 million public offering of 11.8 million shares of common stock.

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

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

Earnings Guidance

2020 GAAP and ongoing earnings guidance is a range of $2.73 to $2.83 per share.[(a)]

Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns.
- Weather-normalized retail electric sales are projected to increase ~1%, including impact of leap year.
- Weather-normalized retail firm natural gas sales are projected to increase ~1%, including impact of leap year.
- Capital rider revenue is projected to increase $45 million to $55 million (net of PTCs). PTCs are credited to customers, through capital riders and reductions to electric margin.
- O&M expenses are projected to increase approximately 1% to 2%.
- Depreciation expense is projected to increase approximately $160 million to $170 million.
- Property taxes are projected to increase approximately $35 million to $45 million.
- Interest expense (net of AFUDC — debt) is projected to increase $50 million to $60 million.
- AFUDC — equity is projected to increase approximately $10 million to $20 million.
- The ETR is projected to be approximately 0%. The ETR reflects benefits of PTCs which are credited to customers through electric margin and will not impact net income.

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

Off-Balance Sheet Arrangements

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

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 7, incorporated by reference.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

Management Report on Internal Control Over Financial Reporting

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

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

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2019. 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, 2019, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

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

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman, President, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer
Feb. 21, 2020	Feb. 21, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2019, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

Basis for Opinions

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matter

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

Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements - Refer to Notes 4 and 12 to the consolidated financial statements

Critical Audit Matter Description

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

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

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant, and 3) a refund due to customers. Given that management’s accounting judgements are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

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

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management’s controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of the Commissions’ treatment of similar costs under similar circumstances. We also evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects. If the full recovery of project costs is being challenged by intervenors, we evaluated management’s assessment of the probability of a disallowance. We evaluated the external information and compared to the Company’s recorded regulatory assets and liabilities for completeness.
- We obtained management’s analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management’s assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 21, 2020

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

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

	Year Ended Dec. 31		
	2019	2018	2017
Operating revenues			
Electric	$ 9,575	$ 9,719	$ 9,676
Natural gas	1,868	1,739	1,650
Other	86	79	78
Total operating revenues	11,529	11,537	11,404
Operating expenses			
Electric fuel and purchased power	3,510	3,854	3,757
Cost of natural gas sold and transported	918	843	823
Cost of sales — other	40	35	34
Operating and maintenance expenses	2,338	2,352	2,270
Conservation and demand side management program expenses	285	290	273
Depreciation and amortization	1,765	1,642	1,479
Taxes (other than income taxes)	569	556	545
Total operating expenses	9,425	9,572	9,181
Operating income	2,104	1,965	2,223
Other income (expense), net	16	(14)	(10)
Equity earnings of unconsolidated subsidiaries	39	35	30
Allowance for funds used during construction — equity	77	108	75
Interest charges and financing costs			
Interest charges — includes other financing costs of $26, $25 and $24, respectively	773	700	663
Allowance for funds used during construction — debt	(37)	(48)	(35)
Total interest charges and financing costs	736	652	628
Income before income taxes	1,500	1,442	1,690
Income taxes	128	181	542
Net income	$ 1,372	$ 1,261	$ 1,148
Weighted average common shares outstanding:			
Basic	519	511	509
Diluted	520	511	509
Earnings per average common share:			
Basic	$ 2.64	$ 2.47	$ 2.26
Diluted	2.64	2.47	2.25

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2019	2018	2017
Net income	$ 1,372	$ 1,261	$ 1,148
Other comprehensive (loss) income			
Defined pension and other postretirement benefits:			
Net pension and retiree medical loss arising during the period, net of tax of $0, $(2) and $(2), respectively	—	(6)	(3)
Reclassification of loss to net income, net of tax of $1, $3 and $5, respectively	3	9	7
Derivative instruments:			
Net fair value decrease, net of tax of $(8), $(2) and $0, respectively	(23)	(5)	—
Reclassification of loss to net income, net of tax of $1, $1 and $2, respectively	3	3	3
Total other comprehensive (loss) income	(17)	1	7
Total comprehensive income	$ 1,355	$ 1,262	$ 1,155

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2019	2018	2017
Operating activities			
Net income	$ 1,372	$ 1,261	$ 1,148
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,785	1,659	1,495
Nuclear fuel amortization	119	122	114
Deferred income taxes	143	218	640
Allowance for equity funds used during construction	(77)	(108)	(75)
Equity earnings of unconsolidated subsidiaries	(39)	(35)	(30)
Dividends from unconsolidated subsidiaries	40	37	41
Provision for bad debts	42	42	39
Share-based compensation expense	58	45	57
Net realized and unrealized hedging and derivative transactions	45	22	2
Changes in operating assets and liabilities:			
Accounts receivable	(20)	(105)	(60)
Accrued unbilled revenues	42	9	(34)
Inventories	(84)	(65)	(3)
Other current assets	25	18	9
Accounts payable	(12)	90	43
Net regulatory assets and liabilities	(66)	223	(16)
Other current liabilities	(15)	(61)	(38)
Pension and other employee benefit obligations	(135)	(179)	(133)
Other, net	40	(71)	(73)
Net cash provided by operating activities	3,263	3,122	3,126
Investing activities			
Utility capital/construction expenditures	(4,225)	(3,957)	(3,244)
Purchases of investment securities	(995)	(853)	(1,697)
Proceeds from the sale of investment securities	975	833	1,669
Other, net	(98)	(9)	(24)
Net cash used in investing activities	(4,343)	(3,986)	(3,296)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(443)	225	422
Proceeds from issuance of long-term debt	2,920	1,675	1,518
Repayments of long-term debt, including reacquisition premiums	(949)	(452)	(1,030)
Proceeds from issuance of common stock	458	230	—
Dividends paid	(791)	(730)	(721)
Other, net	(14)	(20)	(21)
Net cash provided by financing activities	1,181	928	168
Net change in cash, cash equivalents and restricted cash	101	64	(2)
Cash, cash equivalents and restricted cash at beginning of period	147	83	85
Cash, cash equivalents and restricted cash at end of period	$ 248	$ 147	$ 83
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (698)	$ (633)	$ (616)
Cash received for income taxes, net	53	27	44
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 421	$ 388	$ 464
Inventory and other asset transfers to property, plant and equipment	88	129	63
Operating lease right-of-use assets	1,843	—	—
Allowance for equity funds used during construction	77	108	75
Issuance of common stock for reinvested dividends and equity awards	63	67	31

See Notes to Consolidated Financial Statements

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

	Dec. 31 2019	Dec. 31 2018
Assets		
Current assets		
Cash and cash equivalents	$ 248	$ 147
Accounts receivable, net	837	860
Accrued unbilled revenues	713	755
Inventories	544	548
Regulatory assets	488	464
Derivative instruments	55	87
Prepaid taxes	43	79
Prepayments and other	185	154
Total current assets	3,113	3,094
Property, plant and equipment, net	39,483	36,944
Other assets		
Nuclear decommissioning fund and other investments	2,731	2,317
Regulatory assets	2,935	3,326
Derivative instruments	22	34
Operating lease right-of-use assets	1,672	—
Other	492	272
Total other assets	7,852	5,949
Total assets	$ 50,448	$ 45,987
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 702	$ 406
Short-term debt	595	1,038
Accounts payable	1,294	1,237
Regulatory liabilities	407	436
Taxes accrued	466	450
Accrued interest	192	174
Dividends payable	212	195
Derivative instruments	38	61
Other	662	463
Total current liabilities	4,568	4,460
Deferred credits and other liabilities		
Deferred income taxes	4,509	4,165
Deferred investment tax credits	49	54
Regulatory liabilities	5,077	5,187
Asset retirement obligations	2,701	2,568
Derivative instruments	175	129
Customer advances	203	199
Pension and employee benefit obligations	785	994
Operating lease liabilities	1,549	—
Other	186	206
Total deferred credits and other liabilities	15,234	13,502
Commitments and contingencies		
Capitalization		
Long-term debt	17,407	15,803
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 524,539,000 and 514,036,787 shares outstanding at Dec. 31, 2019 and 2018, respectively	1,311	1,285
Additional paid in capital	6,656	6,168
Retained earnings	5,413	4,893
Accumulated other comprehensive loss	(141)	(124)
Total common stockholders' equity	13,239	12,222
Total liabilities and equity	$ 50,448	$ 45,987

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in millions, shares in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2016	507,223	$ 1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				1,148		1,148
Other comprehensive loss					7	7
Dividends declared on common stock ($1.44 per share)				(736)		(736)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			16	(3)		13
Adoption of ASU No. 2018-02				22	(22)	—
Balance at Dec. 31, 2017	507,763	$ 1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,261		1,261
Other comprehensive income					1	1
Dividends declared on common stock ($1.52 per share)				(780)		(780)
Issuances of common stock	6,296	16	254			270
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			17	(1)		16
Balance at Dec. 31, 2018	514,037	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222
Net income				1,372		1,372
Other comprehensive income					(17)	(17)
Dividends declared on common stock ($1.62 per share)				(846)		(846)
Issuances of common stock	10,508	26	468			494
Repurchases of common stock	(6)	—	—			—
Share-based compensation			20	(6)		14
Balance at Dec. 31, 2019	524,539	$ 1,311	$ 6,656	$ 5,413	$ (141)	$ 13,239

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

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

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

Xcel Energy Inc.'s nonregulated subsidiaries include Eloigne, Capital Services and the newly formed MEC Holdings LLC. Eloigne invests in rental housing projects that qualify for low-income housing tax credits. Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Nicollet Project Holdings LLC, Xcel Energy Venture Holdings Inc. and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated, unless a different treatment is appropriate for rate regulated transactions.

Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries.

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

Xcel Energy's consolidated financial statements are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts. Certain amounts in the 2018 and 2017 consolidated financial statements or notes have been reclassified to conform to the 2019 presentation for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

Xcel Energy has evaluated events occurring after Dec. 31, 2019 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — Xcel Energy Inc.'s regulated utility subsidiaries account for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

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

See Note 4 for further information.

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

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

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

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

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

See Note 7 for further information.

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

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.3% for 2019, 3.1% for 2018 and 2017.

See Note 3 for further information.

AROs — Xcel Energy 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. The utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs.

The accumulated removal costs for these obligations are reflected in the consolidated balance sheets as a regulatory liability.

See Note 12 for further information.

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

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

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

See Note 10 and 12 for further information.

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

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

See Note 11 for further information.

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

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

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 12 for further information.

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

Xcel Energy does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. Xcel Energy presents its revenues net of any excise or sales taxes or fees. The utility subsidiaries recognize sales to customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other RTO revenues and charges are recorded on a net basis in cost of sales.

See Note 6 for further information.

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

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

At both Dec. 31, 2019 and 2018, the allowance for bad debts was $55 million.

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

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Inventories		
Materials and supplies	$ 270	$ 271
Fuel	191	170
Natural gas	83	107
Total inventories	$ 544	$ 548

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

Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

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

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; and interest rate hedging transactions are recorded as a component of interest expense.

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

See Note 10 for further information.

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

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

See Note 10 for further information.

Other Utility Items

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

Alternative Revenue — Certain rate rider mechanisms (including decoupling and CIP/DSM programs) qualify as alternative revenue programs. 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, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

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

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

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

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

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

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

2. Accounting Pronouncements

Recently Issued

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after Dec. 15, 2019 and will be applied using a modified-retrospective approach, with a cumulative-effect adjustment to retained earnings as of Jan. 1, 2020.

Xcel Energy expects the impact of adoption of the new standard to include first-time recognition of expected credit losses (i.e., bad debt expense) on unbilled revenues, with the initial allowance established at Jan. 1, 2020 charged to retained earnings. Recognition of this allowance and other impacts of adoption are expected to be immaterial to the consolidated financial statements.

Recently Adopted

Leases — In 2016, the FASB issued *Leases*, *Topic 842 (ASC Topic 842)*, which provides new accounting and disclosure guidance for leasing activities, most significantly requiring that operating leases be recognized on the balance sheet. Xcel Energy adopted the guidance on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions on whether agreements existing before the adoption date contain leases and whether existing leases are operating or finance leases; ASC Topic 842 refers to capital leases as finance leases.

Specifically, for land easement contracts, Xcel Energy has elected the practical expedient provided by *ASU No. 2018-01 Leases: Land Easement Practical Expedient for Transition to Topic 842*, and as a result, only those easement contracts entered on or after Jan. 1, 2019 will be evaluated to determine if lease treatment is appropriate.

Xcel Energy also utilized the transition practical expedient offered by *ASU No. 2018-11 Leases: Targeted Improvements* to implement the standard on a prospective basis. As a result, reporting periods in the consolidated financial statements beginning Jan. 1, 2019 reflect the implementation of ASC Topic 842, while prior periods continue to be reported in accordance with *Leases, Topic 840 (ASC Topic 840)*. Other than first-time recognition of operating leases on its consolidated balance sheet, the implementation of ASC Topic 842 did not have a significant impact on Xcel Energy's consolidated financial statements. Adoption resulted in recognition of approximately $1.7 billion of operating lease ROU assets and current/noncurrent operating lease liabilities.

See Note 12 for leasing disclosures.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Property, plant and equipment		
Electric plant	$ 44,355	$ 41,472
Natural gas plant	6,560	6,210
Common and other property	2,341	2,154
Plant to be retired [(a)]	259	322
CWIP	2,329	2,091
Total property, plant and equipment	55,844	52,249
Less accumulated depreciation	(16,735)	(15,659)
Nuclear fuel	2,909	2,771
Less accumulated amortization	(2,535)	(2,417)
Property, plant and equipment, net	$ 39,483	$ 36,944

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

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2019:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Minnesota				
Electric generation:				
Sherco Unit 3	$ 603	$ 426	$ 4	59%
Sherco common facilities	145	103	2	80
Sherco substation	5	3	—	59
Electric transmission:				
CapX2020	972	92	2	51
Grand Meadow	11	3	—	50
Total NSP-Minnesota	$ 1,736	$ 627	$ 8	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Wisconsin				
Electric transmission:				
La Crosse, WI to Madison, WI	$ 187	$ 7	$ —	37%
CapX2020	169	19	—	80
Total NSP-Wisconsin	$ 356	$ 26	$ —	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
PSCo				
Electric generation:				
Hayden Unit 1	$ 152	$ 81	$ —	76%
Hayden Unit 2	149	71	—	37
Hayden common facilities	41	22	—	53
Craig Units 1 and 2	81	41	—	10
Craig common facilities	39	22	—	7
Comanche Unit 3	887	149	1	67
Comanche common facilities	29	3	—	82
Electric transmission:				
Transmission and other facilities	174	62	1	Various
Gas transmission:				
Rifle, CO to Avon, CO	22	7	—	60
Gas transmission compressor	9	1	—	50
Total PSCo	$ 1,583	$ 459	$ 2	

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

4. Regulatory Assets and Liabilities

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

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2019		Dec. 31, 2018	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	11	Various	$ 85	$ 1,328	$ 87	$ 1,500
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	271	—	264
Net AROs [(a)]	1, 12	Plant lives	—	269	—	452
Excess deferred taxes — TCJA	7	Various	39	239	—	296
Depreciation differences		One to twelve years	15	140	18	107
Environmental remediation costs	1, 12	Various	36	131	17	155
Benson biomass PPA termination and asset purchase		Ten years	9	73	10	86
Contract valuation adjustments [(b)]	1, 10	Term of related contract	20	62	17	77
Purchased power contract costs		Term of related contract	5	61	4	63
Laurentian biomass PPA termination		Five years	19	54	18	73
PI extended power uprate		Sixteen years	3	53	3	56
Losses on reacquired debt		Term of related debt	4	41	4	44
State commission adjustments		Plant lives	1	31	1	29
Property tax		Various	2	30	14	10
Conservation programs [(c)]	1	One to two years	27	26	42	28
Nuclear refueling outage costs	1	One to two years	43	17	37	14
Sales true-up and revenue decoupling		One to two years	54	16	38	7
Renewable resources and environmental initiatives		One to two years	72	10	39	9
Gas pipeline inspection and remediation costs		One to two years	26	8	28	3
Deferred purchased natural gas and electric energy costs		One to three years	6	6	57	13
Other		Various	22	69	30	40
Total regulatory assets			$ 488	$ 2,935	$ 464	$ 3,326

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

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

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

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2019		Dec. 31, 2018	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 75	$ 3,523	$ 157	$ 3,715
Plant removal costs	1, 12	Plant lives	—	1,217	—	1,175
Effects of regulation on employee benefit costs [(b)]		Various	—	196	—	137
Renewable resources and environmental initiatives		Various	—	45	9	54
ITC deferrals [(c)]	1	Various	—	38	—	40
Deferred electric, natural gas and steam production costs		Less than one year	138	—	102	—
Contract valuation adjustments [(d)]	1, 10	Less than one year	19	—	26	—
Conservation programs [(e)]	1	Less than one year	37	—	36	—
DOE settlement		Less than one year	37	—	19	—
Other		Various	101	58	87	66
Total regulatory liabilities [(f)]			$ 407	$ 5,077	$ 436	$ 5,187

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

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

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

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

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

(f) Revenue subject to refund of $28 million and $29 million for 2019 and 2018, respectively, is included in other current liabilities.

At Dec. 31, 2019 and 2018, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations, net AROs and Laurentian biomass PPA termination costs/obligations. In addition, regulatory assets included $544 million and $512 million at Dec. 31, 2019 and 2018, respectively, of past expenditures not earning a return. Amounts primarily related to funded pension obligations, sales true-up and revenue decoupling, purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

Commercial paper and term loan borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2019	Year Ended Dec. 31		
		2019	2018	2017
Borrowing limit	$ 3,600	$ 3,600	$ 3,250	$ 3,250
Amount outstanding at period end	595	595	1,038	814
Average amount outstanding	663	1,115	788	644
Maximum amount outstanding	945	1,780	1,349	1,247
Weighted average interest rate, computed on a daily basis	2.40%	2.72%	2.34%	1.35%
Weighted average interest rate at end of period	2.34	2.34	2.97	1.90

Term Loan Agreement — In December 2019, Xcel Energy Inc. entered into a $500 million 364-Day Term Loan Agreement to pay down borrowings and terminate the expiring $500 million term loan made to Xcel Energy under the 364-Day Term Loan Agreement dated as of Dec. 4, 2018. The loan is unsecured and matures Dec. 1, 2020. Xcel Energy has an option to request an extension through Nov. 30, 2021. Term loan includes one financial covenant, requiring Xcel Energy's consolidated funded debt to total capitalization ratio to be less than or equal to 65 percent. Interest is at a rate equal to either the Eurodollar rate, plus 50.0 basis points, or an alternate base rate.

Term loan borrowings as of Dec. 31, 2019:

(Millions of Dollars)	Limit	Amount Used	Available
Xcel Energy Inc.	$ 500	$ 500	$ —

Bilateral Credit Agreement — In March 2019, NSP-Minnesota entered into a one-year uncommitted bilateral credit agreement. The agreement is limited in use to support letters of credit.

As of Dec. 31, 2019, outstanding letters of credit under the Bilateral Credit Agreement were as follows:

(Millions of Dollars)	Limit	Amount Used	Available
NSP-Minnesota	$ 75	$ 22	$ 53

Letters of Credit — Xcel Energy uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2019 and 2018, there were $20 million and $49 million of letters of credit outstanding under the credit facilities. Amounts approximate their fair value.

Credit Facilities — In order to use commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreements — In June 2019, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements was increased to $3.1 billion, with the following changes:

- Maturity extended from June 2021 to June 2024;
- Borrowing limit for Xcel Energy was increased from $1.0 billion to $1.25 billion;
- Borrowing limit for SPS was increased from $400 million to $500 million; and
- Added swingline subfacility for Xcel Energy up to $75 million

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio[a]		Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested [b]
	2019	2018		
Xcel Energy Inc. [c]	58%	58%	$ 200	2
NSP-Wisconsin	48	48	N/A	1
NSP-Minnesota	48	48	100	2
SPS	46	46	50	2
PSCo	44	46	100	2

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

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

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

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2019, Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2019:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available
Xcel Energy Inc.	$ 1,250	$ —	$ 1,250
PSCo	700	9	691
NSP-Minnesota	500	2	498
SPS	500	40	460
NSP-Wisconsin	150	65	85
Total	$ 3,100	$ 116	$ 2,984

(a) These credit facilities mature in June 2024.

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2019 and 2018.

Long-Term Borrowings and Other Financing Instruments

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

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

Xcel Energy Inc.

Financing Instrument	Interest Rate	Maturity Date	2019	2018
Unsecured senior notes [d]	4.70%	May 15, 2020	$ —	$ 550
Unsecured senior notes	2.40	March 15, 2021	400	400
Unsecured senior notes	2.60	March 15, 2022	300	300
Unsecured senior notes	3.30	June 1, 2025	250	250
Unsecured senior notes	3.30	June 1, 2025	350	350
Unsecured senior notes	3.35	Dec. 1, 2026	500	500
Unsecured senior notes [a]	4.00	June 15, 2028	130	—
Unsecured senior notes [b]	4.00	June 15, 2028	500	500
Unsecured senior notes [a]	2.60	Dec. 1, 2029	500	—
Unsecured senior notes	6.50	July 1, 2036	300	300
Unsecured senior notes	4.80	Sept. 15, 2041	250	250
Unsecured senior notes [a]	3.50	Dec. 1, 2049	500	—
Elimination of PSCo capital lease obligation with affiliates [c]			—	(60)
Unamortized discount			(5)	(5)
Unamortized debt issuance cost			(28)	(21)
Current maturities (capital lease obligation) [c]			—	2
Total long-term debt			$ 3,947	$ 3,316

(a) 2019 financing.

(b) 2018 financing.

(c) Xcel Energy adopted ASC 842 on Jan. 1, 2019, which refers to capital leases as finance leases. Under ASC 842, the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities rather than debt.

(d) Note was redeemed on Dec. 23, 2019.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	2.20%	Aug. 15, 2020	$ 300	$ 300
First mortgage bonds	2.15	Aug. 15, 2022	300	300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.13	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.13	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sept. 15, 2047	600	600
First mortgage bonds [a]	2.90	March 1, 2050	600	—
Unamortized discount			(31)	(21)
Unamortized debt issuance cost			(48)	(42)
Current maturities			(300)	—
Total long-term debt			$ 5,221	$ 4,937

(a) 2019 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2019	2018
City of La Crosse resource recovery bond	6.00%	Nov 1, 2021	$ 19	$ 19
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	6.38	Sept. 1, 2038	200	200
First mortgage bonds	3.70	Oct. 1, 2042	100	100
First mortgage bonds	3.75	Dec. 1, 2047	100	100
First mortgage bonds [a]	4.20	Sept. 1, 2048	200	200
Unamortized discount			(3)	(3)
Unamortized debt issuance cost			(8)	(9)
Total long-term debt			$ 808	$ 807

(a) 2018 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds [d]	5.13%	June 1, 2019	$ —	$ 400
First mortgage bonds	3.20	Nov. 15, 2020	400	400
First mortgage bonds	2.25	Sept. 15, 2022	300	300
First mortgage bonds	2.50	March 15, 2023	250	250
First mortgage bonds	2.90	May 15, 2025	250	250
First mortgage bonds [b]	3.70	June 15, 2028	350	350
First mortgage bonds	6.25	Sept. 1, 2037	350	350
First mortgage bonds	6.50	Aug. 1, 2038	300	300
First mortgage bonds	4.75	Aug. 15, 2041	250	250
First mortgage bonds	3.60	Sept. 15, 2042	500	500
First mortgage bonds	3.95	March 15, 2043	250	250
First mortgage bonds	4.30	March 15, 2044	300	300
First mortgage bonds	3.55	June 15, 2046	250	250
First mortgage bonds	3.80	June 15, 2047	400	400
First mortgage bonds [b]	4.10	June 15, 2048	350	350
First mortgage bonds [a]	4.05	Sept. 15, 2049	400	—
First mortgage bonds [a]	3.20	March 1, 2050	550	—
Capital lease obligations [c]	11.20 - 14.30	2025 - 2060	—	145
Unamortized discount			(24)	(14)
Unamortized debt issuance cost			(41)	(33)
Current maturities			(400)	(406)
Total long-term debt			$ 4,985	$ 4,592

(a) 2019 financing.

(b) 2018 financing.

(c) PSCo adopted ASC 842 on Jan. 1, 2019, which refers to capital leases as finance leases. Under ASC 842, the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities rather than debt.

(d) Bond was redeemed on March 29, 2019.

SPS

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	3.30%	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds [b]	4.40	Nov. 15, 2048	300	300
First mortgage bonds [a]	3.75	June 15, 2049	300	—
Unamortized discount			(7)	(4)
Unamortized debt issuance cost			(23)	(20)
Total long-term debt			$ 2,420	$ 2,126

(a) 2019 financing.

(b) 2018 financing.

Other Subsidiaries

Financing Instrument	Interest Rate	Maturity Date	2019	2018
Various Eloigne affordable housing project notes	0.00% - 6.90%	2020 — 2052	$ 28	$ 26
Current maturities			(2)	(1)
Total long-term debt			$ 26	$ 25

Maturities of long-term debt:

(Millions of Dollars)	
2020	$ 702
2021	421
2022	900
2023	650
2024	552

Deferred Financing Costs — Deferred financing costs of approximately $148 million and $126 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2019 and 2018, respectively.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. In August 2019, Xcel Energy settled the forward equity agreements by physically delivering 9.4 million shares of common equity for cash proceeds of $453 million.

In November 2019, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $743 million public offering of 11.8 million shares of Xcel Energy common stock. The initial forward agreement was for 10.3 million shares with an additional agreement for 1.5 million shares exercised at the option of the banking counterparty.

At Dec. 31, 2019, the forward agreements could have been settled with physical delivery of 11.8 million common shares to the banking counterparty in exchange for cash of $739 million. The forward instruments could also have been settled at Dec. 31, 2019 with delivery of approximately $6 million of cash or approximately 0.1 million shares of common stock to the counterparty, if Xcel Energy unilaterally elected net cash or net share settlement, respectively.

The forward price used to determine amounts due at settlement is calculated based on the November 2019 public offering price for Xcel Energy's common stock of $62.69, increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the instruments are outstanding.

Xcel Energy may settle the agreements at any time up to the maturity date of Dec. 31, 2020. Depending on settlement timing, cash proceeds are expected to be approximately $730 million to $740 million.

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

Other Equity — Xcel Energy issued $39 million of equity annually through the DRIP program during the years ended Dec. 31, 2019 and 2018, respectively. Program allows stockholders to elect dividend reinvestment in Xcel Energy common stock through a non-cash transaction. See Note 8 for equity items related to share based compensation.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2019 and 2018
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

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

Common Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) as of Dec. 31, 2019	Common Stock Outstanding (Shares) as of Dec. 31, 2018
1,000,000,000	$ 2.50	524,539,000	514,036,787

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

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS, which are more restrictive than those imposed by the FERC. Requirements and actuals as of Dec. 31, 2019:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2019
NSP-Minnesota	47.1%	57.5%	52.3%
NSP-Wisconsin	51.5	N/A	51.8
SPS [a]	45.0	55.0	54.4

(a) Excludes short-term debt.

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,147	$ 11,634	$ 12,700
NSP-Wisconsin [a]	12	1,827	N/A
SPS [b]	535	5,304	N/A

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

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

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

Amounts authorized to issue as of Dec. 31, 2019:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.93% of total capitalization (a)	$ 1,905 (a)
NSP-Wisconsin	$ — (b)	150
SPS	— (c)	600
PSCo	150	800

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

(b) NSP-Wisconsin filed for additional long-term debt authorization in December 2019.

(c) SPS filed for additional long-term debt authorization in February 2020.

6. Revenues

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

	Year Ended Dec. 31, 2019			
(Millions of Dollars)	**Electric**	**Natural Gas**	**All Other**	**Total**
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,877	$ 1,127	$ 41	$ 4,045
C&I	4,844	567	29	5,440
Other	130	—	4	134
Total retail	7,851	1,694	74	9,619
Wholesale	737	—	—	737
Transmission	507	—	—	507
Other	49	120	—	169
Total revenue from contracts with customers	9,144	1,814	74	11,032
Alternative revenue and other	431	54	12	497
Total revenues	$ 9,575	$ 1,868	$ 86	$ 11,529

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

7. Income Taxes

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

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

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

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

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

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

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

Tax Year(s)	Expiration
2009 - 2013	June 2020
2014 - 2016	September 2020

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2019, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of Dec. 31, 2019, no adjustments have been proposed.

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

As of Dec. 31, 2019, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2014

- In 2018, Wisconsin began an audit of tax years 2014 - 2016. As of Dec. 31, 2019, no material adjustments have been proposed.
- Xcel Energy had no other state income tax audits in progress for its major operating jurisdictions as of Dec. 31, 2019.

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

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 35	$ 28
Unrecognized tax benefit — Temporary tax positions	9	9
Total unrecognized tax benefit	$ 44	$ 37

Changes in unrecognized tax benefits:

(Millions of Dollars)	2019	2018	2017
Balance at Jan. 1	$ 37	$ 39	$ 134
Additions based on tax positions related to the current year	10	9	6
Reductions based on tax positions related to the current year	(4)	(4)	(4)
Additions for tax positions of prior years	1	2	15
Reductions for tax positions of prior years	—	(4)	(105)
Settlements with taxing authorities	—	(5)	(7)
Balance at Dec. 31	$ 44	$ 37	$ 39

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

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (40)	$ (35)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $29 million and $24 million at Dec. 31, 2019 and Dec. 31, 2018, respectively.

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

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

No amounts were payable for interest related to unrecognized tax benefits as of Dec. 31, 2019, 2018 or 2017. No interest income related to unrecognized tax benefits was recorded in 2019 or 2018, and $3 million was recorded in 2017.

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2019, 2018 or 2017.

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

(Millions of Dollars)	2019	2018
Federal tax credit carryforwards	$ 639	$ 553
Valuation allowances for federal credit carryforwards	—	(5)
State NOL carryforwards	937	1,104
Valuation allowances for state NOL carryforwards	(19)	(50)
State tax credit carryforwards, net of federal detriment (a)	89	89
Valuation allowances for state credit carryforwards, net of federal benefit (b)	(66)	(69)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2019 and 2018.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $17 million and $18 million as of Dec. 31, 2019 and 2018, respectively.

Federal carryforward periods expire between 2023 and 2039 and state carryforward periods expire between 2020 and 2036.

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

Effective income tax rate for years ended Dec. 31:

	2019	2018 (a)	2017 (a)
Federal statutory rate	21.0%	21.0%	35.0%
State income tax on pretax income, net of federal tax effect	4.9	5.0	4.1
Increases (decreases) in tax from:			
Wind PTCs	(9.4)	(5.2)	(4.7)
Plant regulatory differences (b)	(5.8)	(6.2)	(0.8)
Other tax credits, net of NOL & tax credit allowances	(1.7)	(1.7)	(1.0)
Change in unrecognized tax benefits	0.5	0.4	(0.6)
Tax reform	—	—	1.4
Other, net	(1.0)	(0.7)	(1.3)
Effective income tax rate	8.5%	12.6%	32.1%

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

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions and additional prepaid pension asset amortization.

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

(Millions of Dollars)	2019	2018	2017
Current federal tax (benefit) expense	$ (16)	$ (34)	$ 1
Current state tax expense (benefit)	4	8	(11)
Current change in unrecognized tax expense (benefit)	2	(6)	(83)
Deferred federal tax expense	55	122	460
Deferred state tax expense	83	85	107
Deferred change in unrecognized tax expense	5	11	73
Deferred ITCs	(5)	(5)	(5)
Total income tax expense	$ 128	$ 181	$ 542

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

(Millions of Dollars)	2019	2018	2017
Deferred tax expense (benefit) excluding items below	$ 344	$ 320	$ (2,939)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(206)	(102)	3,583
Tax benefit (expense) allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	5	—	(4)
Deferred tax expense	$ 143	$ 218	$ 640

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

(Millions of Dollars)	2019	2018 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 5,474	$ 5,082
Operating lease assets	449	—
Regulatory assets	598	599
Pension expense	173	178
Other	70	60
Total deferred tax liabilities	$ 6,764	$ 5,919
Deferred tax assets:		
Regulatory liabilities	$ 847	$ 879
Operating lease liabilities	449	—
Tax credit carryforward	727	642
NOL carryforward	38	51
NOL and tax credit valuation allowances	(67)	(79)
Other employee benefits	128	124
Deferred ITCs	14	16
Rate refund	26	60
Other	93	61
Total deferred tax assets	$ 2,255	$ 1,754
Net deferred tax liability	$ 4,509	$ 4,165

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

8. Share-Based Compensation

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

- Omnibus Incentive Plan - 7.0 million shares; and
- Executive Annual Incentive Award Plan - 1.2 million shares.

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

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2019	2018	2017
Granted shares	13	18	15
Grant date fair value	$ 53.46	$ 44.68	$ 42.00

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2019	36	$ 44.29
Granted	13	53.46
Forfeited	—	—
Vested	(19)	41.60
Dividend equivalents	1	57.09
Nonvested restricted stock at Dec. 31, 2019	31	50.15

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

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.3 million time-based equity shares subject only to service conditions were granted annually in 2019, 2018 and 2017, respectively.

The performance conditions for a portion of the awards granted from 2017 to 2019 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled or forfeited after three years, with payouts ranging from zero to 200 percent depending on achievement.

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

(Units in Thousands)	2019	2018	2017
Granted units	483	500	503
Weighted average grant date fair value	$ 49.67	$ 47.60	$ 41.02

Equity awards vested:

(Units in Thousands)	2019	2018	2017
Vested Units	464	475	467
Total Fair Value	$ 29,432	$ 23,393	$ 22,459

Changes in the nonvested portion of equity award units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2019	939	$ 44.30
Granted	483	49.67
Forfeited	(116)	50.19
Vested	(464)	41.09
Dividend equivalents	38	45.22
Nonvested Units at Dec. 31, 2019	880	48.20

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

Stock equivalent units granted:

(Units in Thousands)	2019	2018	2017
Granted units	29	36	51
Weighted average grant date fair value	$ 58.44	$ 45.44	$ 46.05

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2019	688	$ 30.93
Granted	29	58.44
Units distributed	(11)	32.56
Dividend equivalents	19	57.28
Stock equivalent units at Dec. 31, 2019	725	32.72

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Omnibus Incentive Plan. This plan allows Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a peer group of 20 other utility members. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2019	2018	2017
Awards granted	225	239	240

TSR liability awards settled:

(In Thousands)	2019	2018	2017
Awards settled	466	482	454
Settlement amount (cash, common stock and deferred amounts)	$ 24,930	$ 21,534	$ 19,083

TSR liability awards of $21 million were settled in cash in 2019.

Share-Based Compensation Expense — Other than for restricted stock, vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target. Additionally, approximately 0.3 million of equity award units were granted annually in 2017 - 2019, with vesting subject only to service conditions of three years.

Generally, these instruments are considered to be equity awards as the award settlement determination (shares or cash) is made by Xcel Energy, not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement.

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

Compensation costs related to share-based awards:

(Millions of Dollars)	2019	2018	2017
Compensation cost for share-based awards [(a)]	$ 58	$ 45	$ 57
Tax benefit recognized in income	15	12	22

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

There was approximately $40 million in 2019 and $38 million in 2018 of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.6 years.

9. Earnings Per Share

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

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

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

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

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

Diluted common shares outstanding included common stock equivalents of 1.3 million, 0.5 million and 0.6 million shares for 2019, 2018 and 2017.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices;
- 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; and
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

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

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

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

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

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

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

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

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

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

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

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

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

Unrealized gains for the nuclear decommissioning fund were $706 million and $450 million as of Dec. 31, 2019 and 2018, respectively, and unrealized losses were $6 million and $45 million as of Dec. 31, 2019 and 2018, respectively.

Non-derivative instruments with recurring fair value measurements:

	Dec. 31, 2019					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 33	$ 33	$ —	$ —	$ —	$ 33
Commingled funds	733	—	—	—	935	935
Debt securities	489	—	495	13	—	508
Equity securities	485	962	2	—	—	964
Total	$ 1,740	$ 995	$ 497	$ 13	$ 935	$ 2,440

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $155 million of equity investments in unconsolidated subsidiaries and $136 million of rabbi trust assets and miscellaneous investments.

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

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

For the years ended Dec. 31, 2019 and 2018, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2019:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ (7)	$ 111	$ 246	$ 158	$ 508

Rabbi Trusts

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

Cost and fair value of assets held in rabbi trusts:

	December 31, 2019				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 17	$ 17	$ —	$ —	$ 17
Mutual funds	57	65	—	—	65
Total	$ 74	$ 82	$ —	$ —	$ 82

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

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

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

Derivative Fair Value Measurements

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

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

As of Dec. 31, 2019, accumulated other comprehensive losses related to interest rate derivatives included $5 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings.

As of Dec. 31, 2019, Xcel Energy had no unsettled interest rate swaps outstanding. These interest rate derivatives were designated as hedges, and as such, changes in fair value are recorded to other comprehensive income.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

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

As of Dec. 31, 2019, Xcel Energy had no commodity derivative contracts designated as cash flow hedges. Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2019 and 2018.

As of Dec. 31, 2019, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

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

Gross notional amount of commodity forwards, options and FTRs at Dec. 31:

(Millions of Dollars) [(a) (b)]	2019	2018
MWh of electricity	95	87
MMBtu of natural gas	110	92

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis but weighted for the probability of exercise.

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

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

As of Dec. 31, 2019, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $154 million or 60% of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's Investor Services or Fitch Ratings. Four of the 10 most significant counterparties, comprising $37 million or 14% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. Nine of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

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

(Millions of Dollars)	2019	2018	2017
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (60)	$ (58)	$ (51)
After-tax net unrealized losses related to derivatives accounted for as hedges	(23)	(5)	—
After-tax net realized losses on derivative transactions reclassified into earnings	3	3	3
Adoption of ASU. 2018-02 [(a)]	—	—	(10)
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (80)	$ (60)	$ (58)

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

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2019		
Derivatives designated as cash flow hedges		
Interest rate	$ (30)	$ —
Total	(30)	—
Other derivative instruments		
Electric commodity	—	8
Natural gas commodity	—	(9)
Total	—	(1)
Year Ended Dec. 31, 2018		
Interest rate	(7)	—
Total	(7)	—
Other derivative instruments		
Electric commodity	—	1
Natural gas commodity	—	10
Total	—	11
Year Ended Dec. 31, 2017		
Other derivative instruments		
Electric commodity	—	10
Natural gas commodity	—	(13)
Total	$ —	$ (3)

	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2019			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [(a)]	$ —	$ —
Total	4	—	—
Other derivative instruments			
Commodity trading	—	—	2 [(b)]
Electric commodity	—	(5) [(c)]	—
Natural gas commodity	—	2 [(d)]	(7) [(d)]
Total	—	(3)	(5)
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	4 [(a)]	—	—
Total	4	—	—
Other derivative instruments			
Commodity trading	—	—	14 [(b)]
Electric commodity	—	(1) [(c)]	—
Natural gas commodity	—	(6) [(d)]	(4) [(d)]
Total	—	(7)	10
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	5 [(a)]	—	—
Total	5	—	—
Other derivative instruments			
Commodity trading	—	—	10 [(b)]
Electric commodity	—	(15) [(c)]	—
Natural gas commodity	—	3 [(d)]	(6) [(d)]
Total	$ —	$ (12)	$ 4

(a) Amounts recorded to interest charges.

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

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

(d) Amounts for the year ended Dec. 31, 2019 included no settlement losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses and gains for the years ended Dec. 31, 2018 and 2017 were $1 million and immaterial, respectively. Remaining settlement losses for the years ended Dec. 31, 2019, 2018 and 2017 related to natural gas operations and were recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2019, 2018 and 2017.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies, or for cross default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2019 and 2018, the amounts for derivative instruments in a liability position with such underlying contract provisions were $7 million and none, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2019 and 2018.

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

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Commodity trading	$ 3	$ 51	$ 24	$ 78	$ (52)	$ 26	$ 4	$ 92	$ 2	$ 98	$ (44)	$ 54
Electric commodity	—	—	21	21	(1)	20	—	—	25	25	—	25
Natural gas commodity	—	6	—	6	—	6	—	4	—	4	—	4
Total current derivative assets	$ 3	$ 57	$ 45	$ 105	$ (53)	52	$ 4	$ 96	$ 27	$ 127	$ (44)	83
PPAs (b)						3						4
Current derivative instruments						$ 55						$ 87
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 9	$ 38	$ 7	$ 54	$ (45)	$ 9	$ —	$ 27	$ 5	$ 32	$ (14)	$ 18
Total noncurrent derivative assets	$ 9	$ 38	$ 7	$ 54	$ (45)	9	$ —	$ 27	$ 5	$ 32	$ (14)	18
PPAs (b)						13						16
Noncurrent derivative instruments						$ 22						$ 34

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7	$ —	$ 7	$ —	$ 7
Other derivative instruments:												
Commodity trading	4	59	15	78	(63)	15	4	88	2	94	(60)	34
Electric commodity	—	—	1	1	(1)	—	—	—	—	—	—	—
Natural gas commodity	—	5	—	5	—	5	—	—	—	—	—	—
Total current derivative liabilities	$ 4	$ 64	$ 16	$ 84	$ (64)	20	$ 4	$ 95	$ 2	$ 101	$ (60)	41
PPAs (b)						18						20
Current derivative instruments						$ 38						$ 61
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 2	$ 79	$ 32	$ 113	$ (13)	$ 100	$ —	$ 18	$ 1	$ 19	$ 17	$ 36
Total noncurrent derivative liabilities	$ 2	$ 79	$ 32	$ 113	$ (13)	100	$ —	$ 18	$ 1	$ 19	$ 17	36
PPAs (b)						75						93
Noncurrent derivative instruments						$ 175						$ 129

(a) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2019 and 2018. At both Dec. 31, 2019 and 2018, derivative assets and liabilities included $32 million of obligations to return cash collateral. At Dec. 31, 2019 and 2018, derivative assets and liabilities included rights to reclaim cash collateral of $11 million and $15 million, respectively. Counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

Changes in Level 3 commodity derivatives:

(Millions of Dollars)	Year Ended Dec. 31 2019	2018	2017
Balance at Jan. 1	$ 29	$ 35	$ 17
Purchases	44	59	82
Settlements	(64)	(59)	(97)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(8)	(1)	5
Net gains (losses) recognized as regulatory assets and liabilities	3	(5)	28
Balance at Dec. 31	$ 4	$ 29	$ 35

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

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2017 - 2019.

Fair Value of Long-Term Debt

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

(Millions of Dollars)	2019 Carrying Amount	2019 Fair Value	2018 Carrying Amount	2018 Fair Value
Long-term debt, including current portion	$ 18,109	$ 20,227	$ 16,209	$ 16,755

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2019 and 2018, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants.

The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows.

Obligations of the SERP and nonqualified plan as of Dec. 31, 2019 and 2018 were $39 million and $33 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2019 and in 2018.

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

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

- Investment returns in 2019 were above the assumed level of 6.87%;
- Investment returns in 2018 were below the assumed level of 6.87%;
- Investment returns in 2017 were above the assumed level of 6.87%; and
- In 2020, expected investment-return assumption is 6.87%.

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

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

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

Plan Assets

For each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

(Millions of Dollars)	Dec. 31, 2019 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2018 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 145	$ —	$ —	$ —	$ 145	$ 137	$ —	$ —	$ —	$ 137
Commingled funds	1,408	—	—	1,031	2,439	914	—	—	987	1,901
Debt securities	—	645	4	—	649	—	621	—	—	621
Equity securities	86	—	—	—	86	106	—	—	—	106
Other	(120)	5	—	(20)	(135)	2	5	—	(30)	(23)
Total	$ 1,519	$ 650	$ 4	$ 1,011	$ 3,184	$ 1,159	$ 626	$ —	$ 957	$ 2,742

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

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

	Dec. 31, 2019 [(a)]					Dec. 31, 2018 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 23	$ —	$ —	$ —	$ 23	$ 19	$ —	$ —	$ —	$ 19
Insurance contracts	—	51	—	—	51	—	45	—	—	45
Commingled funds	69	—	—	76	145	133	—	—	40	173
Debt securities	—	228	1	—	229	—	179	—	—	179
Other	—	1	—	—	1	—	1	—	—	1
Total	$ 92	$ 280	$ 1	$ 76	$ 449	$ 152	$ 225	$ —	$ 40	$ 417

(a) See Note 10 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2019. No assets were transferred in or out of Level 3 for 2018.

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

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2019	2018	2019	2018
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,477	$ 3,828	$ 542	$ 621
Service cost	86	94	2	2
Interest cost	145	133	22	22
Plan amendments	1	—	—	—
Actuarial loss (gain)	273	(224)	19	(62)
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	1	1
Benefit payments [(a)]	(281)	(354)	(47)	(50)
Obligation at Dec. 31	$ 3,701	$ 3,477	$ 547	$ 542
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 2,742	$ 3,088	$ 417	$ 461
Actual return on plan assets	568	(142)	56	(13)
Employer contributions	155	150	15	11
Plan participants' contributions	—	—	8	8
Benefit payments	(281)	(354)	(47)	(50)
Fair value of plan assets at Dec. 31	$ 3,184	$ 2,742	$ 449	$ 417
Funded status of plans at Dec. 31	$ (517)	$ (735)	$ (98)	$ (125)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ —	$ —	$ 21	$ —
Current liabilities	—	—	(6)	(7)
Noncurrent liabilities	(517)	(735)	(113)	(118)
Net amounts recognized	$ (517)	$ (735)	$ (98)	$ (125)

(a) Includes approximately $20 million in 2019 and $198 million in 2018 of lump-sum benefit payments used in the determination of a settlement charge.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2019	2018	2019	2018
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	3.49%	4.31%	3.47%	4.32%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	PRI-2012	RP-2014	PRI-2012	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.00%	6.50%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.10%	5.30%
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	3	4

Accumulated benefit obligation for the pension plan was $3,465 million and $3,275 million as of Dec. 31, 2019 and 2018, respectively.

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

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

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Service cost	$ 86	$ 94	$ 94	$ 2	$ 2	$ 2
Interest cost	145	133	147	22	22	24
Expected return on plan assets	(203)	(209)	(209)	(21)	(26)	(25)
Amortization of prior service credit	(5)	(5)	(2)	(10)	(11)	(11)
Amortization of net loss	87	111	107	5	8	7
Settlement charge [(a)]	6	91	81	—	—	—
Net periodic pension cost (credit)	116	215	218	(2)	(5)	(3)
Costs not recognized due to effects of regulation	(1)	(75)	(79)	1	2	—
Net benefit cost (credit) recognized for financial reporting	$ 115	$ 140	$ 139	$ (1)	$ (3)	$ (3)
Significant Assumptions Used to Measure Costs:						
Discount rate	4.31%	3.63%	4.13%	4.32%	3.62%	4.13%
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.87	6.87	6.87	4.50	5.30	5.80

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2019 and 2018, as a result of lump-sum distributions during the 2019 and 2018 plan years, Xcel Energy recorded a total pension settlement charge of $6 million in 2019 and $91 million in 2018, the majority of which was not recognized due to the effects of regulation. A total of $1 million and $11 million was recorded in the consolidated statements of income in 2019 and 2018, respectively.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,447	$ 1,633	$ 95	$ 116
Prior service credit	(15)	(20)	(23)	(33)
Total	$ 1,432	$ 1,613	$ 72	$ 83
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	$ 78	$ 94	$ —	$ —
Noncurrent regulatory assets	1,285	1,446	80	89
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(12)	(10)
Deferred income taxes	18	19	1	1
Net-of-tax accumulated other comprehensive income	51	54	4	4
Total	$ 1,432	$ 1,613	$ 72	$ 83
Measurement date	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2017 — 2020 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $150 million in January 2020;
- $154 million in 2019;
- $150 million in 2018; and
- $162 million in 2017.

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

Voluntary postretirement funding contributions:

- $10 million during 2020;
- $15 million during 2019;
- $11 million during 2018; and
- $20 million during 2017.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2019	2018	2019	2018
Domestic and international equity securities	37%	36%	15%	18%
Long-duration fixed income securities	30	30	—	—
Short-to-intermediate fixed income securities	14	17	72	70
Alternative investments	17	15	9	8
Cash	2	2	4	4
Total	100%	100%	100%	100%

Plan Amendments — The Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) were amended in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

In 2018, the PSCo postretirement plan was amended to add the 5% cash balance formula.

In 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

There were no plan amendments made in 2019 which affected the postretirement benefit obligation.

Projected Benefit Payments

Xcel Energy's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2020	$ 278	$ 44	$ 2	$ 42
2021	263	43	2	41
2022	262	42	2	40
2023	260	41	2	39
2024	255	40	2	38
2025-2029	1,205	181	13	168

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $39 million in 2019, $38 million in 2018 and $37 million in 2017.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans.

Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

Legal

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessing whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation.

Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

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

Two cases remain active which include an MDL matter consisting of a Colorado purported class (Breckenridge) and a Wisconsin purported class (Arandell Corp.).

Breckenridge/Colorado — In February 2019, the MDL panel remanded Breckenridge back to the U.S. District Court in Colorado.

Arandell Corp. — In February 2019, the case was remanded back to the U.S. District Court in Wisconsin.

Xcel Energy has concluded that a loss is remote for both remaining lawsuits.

Line Extension Disputes — In December 2015, the DRC filed a lawsuit seeking monetary damages in the Denver District Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements. The dispute involves claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC's petition to appeal the Denver District Court's dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so.

This claim is similar to the arguments previously raised by the DRC. PSCo filed a motion to dismiss this claim, which was granted in May 2018. The DRC subsequently filed an appeal to the Colorado Court of Appeals. In November 2019, the Colorado Court of Appeals issued an opinion affirming dismissal of the lawsuit based upon lack of subject matter jurisdiction. The Colorado Court of Appeals did not address the second issue based upon issue preclusion. Finally, the Colorado Court of Appeals remanded the case to the Boulder District Court to consider PSCo's request for an award of costs, which it concluded does not include attorneys' fees. The DRC did not file a petition for a Writ of Certiorari to the Colorado Supreme Court by the Dec. 26, 2019 deadline, effectively terminating this litigation.

Rate Matters

MEC Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company (a subsidiary of Southern Company) to purchase MEC, a 760 MW natural gas combined cycle facility, with capacity and energy historically sold to NSP-Minnesota under PPAs expiring in 2026 and 2039, for approximately $650 million.

In September 2019, the MPUC denied NSP-Minnesota's request to purchase MEC as a rate base asset. In January 2020, the MPUC approved Xcel Energy's plan to acquire MEC as a non-regulated investment and step into the terms of the existing PPAs with NSP-Minnesota. A newly formed non-regulated subsidiary of Xcel Energy completed the transaction to purchase MEC on Jan. 17, 2020.

Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, SMMPA (Co-owner of Sherco Unit 3) and insurance companies against GE.

In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the FCA. The insurance providers continued their litigation against GE and the case went to trial.

In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the DOC recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The OAG recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals. NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

In March 2019, MPUC approved NSP-Minnesota's proposal to refund the GE settlement proceeds back to customers through the FCA. It also decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of the pending litigation between GE and NSP-Minnesota's insurers.

MISO ROE Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin.

The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%.

In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C. Circuit subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

On March 21, 2019, FERC announced a NOI seeking public comments on whether, and if so how, to revise ROE policies in light of the D.C. Circuit Court decision. FERC also initiated a NOI on whether to revise its policies on incentives for electric transmission investments, including the RTO membership incentive. In November 2019, the FERC issued an order adopting a new ROE methodology and settling the MISO base ROE at 9.88% (10.38% with the RTO adder), effective Sept. 28, 2016 and for the Nov. 12, 2013 to Feb. 11, 2015 refund period. The FERC also dismissed the second complaint.

In December 2019, MISO TOs filed a request for rehearing. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds. Xcel Energy has recognized a liability for its best estimate of final refunds to customers. It is uncertain when the FERC will act on the requests for rehearing or any other pending matters related to the 2019 NOIs.

Texas Fuel Reconciliation — In December 2018, SPS filed an application with the PUCT for reconciliation of fuel costs for the period Jan. 1, 2016, through June 30, 2018, to determine whether all fuel costs incurred were eligible for recovery. In December 2019, the PUCT issued an order disallowing recovery of costs for Texas customers related to two specific solar PPAs. These PPAs were previously approved by the NMPRC as reasonable, necessary and economic. SPS recorded a total disallowance of approximately $6 million in December 2019.

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

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for a rehearing. Timing of a FERC response to rehearing requests is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. Timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to have sent wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin was named a responsible party for contamination at the Ashland/Northern States Power Lakefront Superfund Site (the Site) in Ashland, Wisconsin. Remediation was completed in 2019 and restoration activities are anticipated to be completed in 2020. Groundwater treatment activities will continue for many years.

The current cost estimate for remediation and restoration of the entire site is approximately $199 million. At Dec. 31, 2019 and 2018, NSP-Wisconsin had a total liability of $23 million and $27 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation and restoration costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation and restoration costs incurred at the Site. In its final December 2019 order approving 2020 and 2021 natural gas base rates, the PSCW authorized continued amortization of costs and application of a 3% carrying charge to the regulatory asset.

MGP, Landfill or Disposal Sites — PSCo is cooperating with the City of Denver on an environmental investigation of the Rice Yards Site in Denver, Colorado, which had various historic industrial uses by multiple parties, including railroad, maintenance shop, scrap metal yard, and MGP operations.

The area is being redeveloped into residential and commercial mixed uses, and PSCo is in discussions with the current property owner regarding legal claims related to the Rice Yards Site.

In addition, Xcel Energy is currently investigating or remediating 12 other MGP, landfill or other disposal sites across its service territories.

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

Environmental Requirements — Water and Waste

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

Xcel Energy is conducting groundwater sampling and, where appropriate, initiating the assessment of corrective measures and evaluating whether corrective action is required at any CCR landfills or surface impoundments. In 2019, groundwater monitoring consistent with the CCR Rule was conducted. In NSP-Minnesota, no results above the groundwater protection standards in the rule were identified. In PSCo, statistically significant increase above background concentration was detected at four locations. Subsequently, assessment monitoring samples were collected, and PSCo is evaluating the results to determine whether corrective action is required. Until PSCo completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows.

In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. In November 2019, the EPA proposed rules in response to this decision.

If finalized in their current form, these rules would require NSP-Minnesota to expedite closure plans for one impoundment at an estimated cost of $2 million and the construction of a new impoundment at the cost of $9 million.

In 2019, Xcel Energy initiated the construction of this new impoundment, an ash pond, expected to be in service in 2020. Upon placing the new ash pond in service, the existing ash pond will be taken out of service, and closure activities as prescribed by the CCR Rule and the facility's National Pollutant Discharge Elimination System permit will be initiated. In addition, the rules proposed by the EPA may require PSCo to expedite the closure of one coal ash impoundment.

Closure costs for existing impoundments are included in the calculation of the ARO liability. See Note 12 for further information.

Federal CWA WOTUS Rule — In 2015, the EPA and U.S. Army Corps of Engineers published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". In 2019, the EPA repealed the 2015 rule and published a draft replacement rule. Until a final rule is issued, Xcel Energy cannot estimate potential impacts, but anticipates costs will be recoverable through regulatory mechanisms.

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

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely cost for complying with impingement and entrainment requirements is approximately $40 million, to be incurred between 2020 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain but could be up to approximately $198 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. The requirements of the first regional haze plans developed by Minnesota and Colorado have been approved and implemented. Texas' first regional haze plan has undergone federal review as described below.

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

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

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking, which was supplemented by an additional agency notice in November 2019. It is not known when the EPA will make a final decision on this proposal.

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

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

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

If the area near the Harrington plant is designated nonattainment in 2020, the TCEQ will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. Xcel Energy cannot evaluate the impacts until the final designation is made and any required state plans are developed.

Xcel Energy believes that should SO_2 control systems be required for a plant, compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

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

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was $2.4 billion and $2.1 billion for 2019 and 2018, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2019	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2019
Electric						
Nuclear	$1,968	$ —	$ —	$ 100	$ —	$2,068
Steam, hydro and other production	177	—	(5)	8	22	202
Wind	119	26	—	7	(6)	146
Distribution	42	—	—	2	—	44
Miscellaneous	7	—	—	—	(7)	—
Natural gas						
Transmission and distribution	249	—	—	11	(24)	236
Miscellaneous	4	—	—	—	(1)	3
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,568	$ 26	$ (5)	$ 128	$ (16)	$2,701

(a) Amounts incurred related to the wind farms placed in service in 2019 for NSP-Minnesota (Lake Benton and Foxtail) and SPS (Hale).

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

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by decreased inflation rates. Changes in steam, hydro and other production AROs primarily related to the cost estimates to remediate ponds at production facilities. Changes in wind AROs were driven by new dismantling studies.

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

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

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

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

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2019. Therefore, an ARO was not recorded for these facilities.

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

Accumulated balances by entity at Dec. 31:

(Millions of Dollars)	2019	2018
NSP-Minnesota	$ 520	$ 485
PSCo	351	344
SPS	175	188
NSP-Wisconsin	171	158
Total Xcel Energy	$ 1,217	$ 1,175

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $13.9 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.5 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government.

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

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.7 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

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

NSP-Minnesota could be subject to annual maximum assessments of approximately $12 million for business interruption insurance and $35 million for property damage insurance if losses exceed accumulated reserve funds.

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

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

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

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

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

NSP-Minnesota had $2.4 billion of assets held in external decommissioning trusts at Dec. 31, 2019. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

	Regulatory Basis	
(Millions of Dollars)	2019	2018
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	688	539
Estimated decommissioning cost obligation (in current dollars)	3,700	3,551
Effect of escalating costs to payment date	7,505	7,654
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 2.39% and 3.33% for 2019 and 2018, respectively)	(5,562)	(6,911)
Discounted decommissioning cost obligation	$ 5,643	$ 4,294
Assets held in external decommissioning trust	$ 2,440	$ 2,055
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	3,203	2,239

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

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

(Millions of Dollars)	2019	2018
Discounted decommissioning cost obligation - regulated basis	$ 5,643	$ 4,294
Differences in discount rate and market risk premium	(2,295)	(1,447)
O&M costs not included for GAAP	(1,280)	(879)
Nuclear production decommissioning ARO - GAAP	$ 2,068	$ 1,968

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	2019	2018	2017
Annual decommissioning recorded as depreciation expense: [(a)] [(b)]	$ 20	$ 20	$ 20

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

(b) Decommissioning expenses in 2019, 2018 and 2017 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2019, 2018 and 2017. The 2017 filing, effective Jan. 1, 2019, has been approved by the MPUC. In December 2019, the MPUC verbally approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2021.

Leases

Xcel Energy evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under ASC Topic 842, adopted by Xcel Energy on Jan. 1, 2019, a contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent Xcel Energy's rights to use leased assets. Starting in 2019, the present value of future operating lease payments are recognized in other current liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of Xcel Energy's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the applicable Xcel Energy subsidiary's estimated incremental borrowing rate (weighted-average of 4.1%). Xcel Energy has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2019
PPAs	$ 1,642
Other	201
Gross operating lease ROU assets	1,843
Accumulated amortization	(171)
Net operating lease ROU assets	$ 1,672

In 2019, ROU assets for finance leases are included in other noncurrent assets, and the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities. Prior to 2019, finance leases were included in property, plant and equipment, the current portion of long-term debt and long-term debt.

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

PSCo accounts for its Totem natural gas storage service and Front Range pipeline arrangements with CIG and WYCO, respectively, as finance leases. Xcel Energy Inc. eliminates 50% of the finance lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

Finance lease ROU assets:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Gross finance lease ROU assets	222	222
Accumulated amortization	(83)	(77)
Net finance lease ROU assets	$ 139	$ 145

Components of lease expense:

(Millions of Dollars)	2019	2018	2017
Operating leases			
PPA capacity payments	$ 221	$ 210	$ 210
Other operating leases [(a)]	34	38	36
Total operating lease expense [(b)]	$ 255	$ 248	$ 246
Finance leases			
Amortization of ROU assets	$ 6	$ 6	$ 5
Interest expense on lease liability	19	19	20
Total finance lease expense	$ 25	$ 25	$ 25

(a) Includes short-term lease expense of $5 million for 2019, 2018 and 2017.

(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating and finance leases as of Dec. 31, 2019:

(Millions of Dollars)	PPA [(a)] [(b)] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [(c)]
2020	$ 236	$ 26	$ 262	$ 14
2021	238	29	267	14
2022	225	28	253	12
2023	214	25	239	12
2024	208	22	230	12
Thereafter	750	115	865	207
Total minimum obligation	1,871	245	2,116	271
Interest component of obligation	(321)	(52)	(373)	(190)
Present value of minimum obligation	$ 1,550	193	1,743	81
Less current portion			(194)	(4)
Noncurrent operating and finance lease liabilities			$ 1,549	$ 77
Weighted-average remaining lease term in years			9.3	37.0

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

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

Operating lease liabilities at Dec. 31, 2019 include a present value of approximately $400 million for MEC PPA capacity payments. In 2020, these operating lease liabilities and related ROU assets will be eliminated from Xcel Energy's consolidated balance sheet following the completed January 2020 purchase of MEC by a newly formed non-regulated subsidiary of Xcel Energy.

Commitments under operating and finance leases as of Dec. 31, 2018:

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

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

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

PPAs and Fuel Contracts

Non-Lease PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with various expiration dates through 2034 for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts contain minimum energy purchase commitments, and total energy payments on those contracts were $102 million, $105 million and $100 million in 2019, 2018 and 2017, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $86 million, $131 million and $168 million in 2019, 2018 and 2017, respectively.

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

At Dec. 31, 2019, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [a]
2020	$ 70	$ 110
2021	78	157
2022	77	173
2023	79	177
2024	74	182
Thereafter	56	146
Total	$ 434	$ 945

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

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2020 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2019:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2020	$ 430	$ 54	$ 343	$ 295
2021	222	103	254	283
2022	135	85	104	269
2023	58	103	53	198
2024	24	74	3	153
Thereafter	74	275	—	860
Total	$ 943	$ 694	$ 757	$ 2,058

VIEs

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

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

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

The utility subsidiaries had approximately 3,986 MW and 3,770 MW of capacity under long-term PPAs at Dec. 31, 2019 and 2018, respectively, with entities that have been determined to be VIEs. Agreements have expiration dates through 2041.

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

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs.

SPS has determined that TUCO is a VIE, however it has concluded that SPS is not the primary beneficiary of TUCO because it does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership.

Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be, provided to the limited partnerships by Eloigne or NSP-Wisconsin.

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

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Current assets	$ 7	$ 5
Property, plant and equipment, net	41	42
Other noncurrent assets	1	1
Total assets	$ 49	$ 48
Current liabilities	$ 8	$ 7
Mortgages and other long-term debt payable	26	26
Other noncurrent liabilities	—	—
Total liabilities	$ 34	$ 33

Other

Technology Agreements — Xcel Energy has a contract that extends through December 2022 with IBM for information technology services. The contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50% of the contract value for early termination. Xcel Energy capitalized or expensed $46 million, $81 million and $98 million associated with the IBM contract in 2019, 2018 and 2017, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $52 million, $46 million and $16 million associated with the Accenture contract in 2019, 2018 and 2017, respectively.

During 2019, Xcel Energy executed a contract with Cognizant for information technology services which extends through 2022. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $3 million associated with the Cognizant contract in 2019.

Committed minimum payments under these obligations:

(Millions of Dollars)	IBM Agreement	Accenture Agreement	Cognizant Agreement
2020	$ 15	$ 11	$ 9
2021	15	—	7
2022	6	—	3
2023	—	—	—
2024	—	—	—
Thereafter	—	—	—

Guarantees and Bond Indemnifications — Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum amount. As of Dec. 31, 2019 and 2018, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding for Xcel Energy were $62 million and $69 million as of Dec. 31, 2019 and 2018.

13. Other Comprehensive Income

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

(Millions of Dollars)	2019 Gains and Losses on Cash Flow Hedges	2019 Defined Benefit Pension and Postretirement Items	2019 Total
Accumulated other comprehensive loss at Jan. 1	$ (60)	$ (64)	$ (124)
Other comprehensive loss before reclassifications (net of taxes of $(8) and $0, respectively)	(23)	—	(23)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $0, respectively)	3 (a)	—	3
Amortization of net actuarial loss (net of taxes of $0 and $1, respectively)	—	3 (b)	3
Net current period other comprehensive (loss) income	(20)	3	(17)
Accumulated other comprehensive loss at Dec. 31	$ (80)	$ (61)	$ (141)

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

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

(a) Included in interest charges.
(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

14. Segments and Related Information

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

Xcel Energy has the following reportable segments:

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

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

Xcel Energy had equity investments in unconsolidated subsidiaries of $155 million and $141 million as of Dec. 31, 2019 and 2018, respectively, included in the natural gas utility and all other segments.

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

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

Xcel Energy's segment information:

(Millions of Dollars)	2019	2018	2017
Regulated Electric			
Operating revenues from external customers	$ 9,575	$ 9,719	$ 9,676
Intersegment revenue	1	1	2
Total revenues	$ 9,576	$ 9,720	$ 9,678
Depreciation and amortization	1,535	1,421	1,298
Interest charges and financing costs	500	449	449
Income tax expense	125	187	528
Net income	1,288	1,177	1,066
Regulated Natural Gas			
Operating revenues from external customers	$ 1,868	$ 1,739	$ 1,650
Intersegment revenue	2	2	1
Total revenues	$ 1,870	$ 1,741	$ 1,651
Depreciation and amortization	219	212	174
Interest charges and financing costs	69	61	57
Income tax expense	48	28	23
Net income	195	187	182
Other			
Total operating revenue	$ 86	$ 79	$ 78
Depreciation and amortization	11	9	7
Interest charges and financing costs	167	142	122
Income tax (benefit)	(45)	(34)	(9)
Net (loss)	(111)	(103)	(100)
Consolidated Total			
Total revenue	$ 11,532	$ 11,540	$ 11,407
Reconciling eliminations	(3)	(3)	(3)
Consolidated total revenue	$ 11,529	$ 11,537	$ 11,404
Depreciation and amortization	1,765	1,642	1,479
Interest charges and financing costs	736	652	628
Income tax expense	128	181	542
Net income	1,372	1,261	1,148

15. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Amounts in millions, except per share data)	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019
Operating revenues	$ 3,141	$ 2,577	$ 3,013	$ 2,798
Operating income	486	410	758	450
Net income	315	238	527	292
EPS total — basic	$ 0.61	$ 0.46	$ 1.02	$ 0.56
EPS total — diluted	0.61	0.46	1.01	0.56
Cash dividends declared per common share	0.405	0.405	0.405	0.405

	Quarter Ended			
(Amounts in millions, except per share data)	March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 2,951	$ 2,658	$ 3,048	$ 2,880
Operating income [(a)]	480	450	696	339
Net income	291	265	491	214
EPS total — basic	$ 0.57	$ 0.52	$ 0.96	$ 0.42
EPS total — diluted	0.57	0.52	0.96	0.42
Cash dividends declared per common share	0.380	0.380	0.380	0.380

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

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure. As of Dec. 31, 2019, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2019 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in Xcel Energy's Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

ITEM 9B — OTHER INFORMATION

None.

PART III

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is expected to occur on April 6, 2020, incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

ITEM 11 — EXECUTIVE COMPENSATION

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item is contained in Xcel Energy Inc.'s definitive Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

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, 2019.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For the three years ended Dec. 31, 2019, 2018, and 2017.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2019, 2018, and 2017.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2019, 2018, and 2017.
	Consolidated Balance Sheets — As of Dec. 31, 2019 and 2018.
	Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2019, 2018, and 2017.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2019, 2018 and 2017.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated May 16, 2012	001-03034	3.01
3.02*	Bylaws of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated Feb. 17, 2016	001-03034	3.01
4.01	Description of Securities			
4.02*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	001-03034	4.01
4.03*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	001-03034	4.01
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.01
4.05*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.03
4.06*	Supplemental Indenture dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated May 10, 2010	001-03034	4.01
4.07*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	001-03034	4.01
4.08*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 1, 2015	001-03034	4.01
4.09*	Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated March 8, 2016	001-03034	4.02
4.10*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	001-03034	4.01
4.11*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	001-03034	4.01
4.12*	Supplemental Indenture No. 12, dated as of Nov. 7, 2019 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating 2.60% Senior Notes, Series Due 2029 and 3.50% Senior Notes, Series due 2049	Xcel Energy Inc. Form 8-K dated Nov. 7, 2019	001-03034	4.01
10.01*	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.17
10.06*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06

10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.08
10.08*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Appendix A
10.09*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	001-03034	Appendix A
10.10*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.11*+	First Amendment to Exhibit 10.10 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.12*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.13*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.14*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.15*+	Second Amendment to Exhibit 10.10 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.16*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.02
10.17*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.18*+	Third Amendment to Exhibit 10.10 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.19*+	Fourth Amendment to Exhibit 10.10 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.20*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.21*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.22*	Forward Sale Agreement, dated Nov. 7, 2018, between Xcel Energy Inc. and Morgan Stanley &Co., LLC	Xcel Energy Inc. Form 8-K dated Nov. 7, 2018	001-03034	10.01
10.23*	Amended and Restated 364-Day Term Loan Agreement dated as of Dec. 4, 2018 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and MUFG Bank, Ltd. as Administrative Agent.	Xcel Energy Inc. Form 8-K dated Dec. 4, 2018	001-03034	99.01
10.24*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.34
10.25*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.35
10.26*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.36
10.27*+	Brett Carter's Sign-On Bonus Terms	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2019	001-03034	10.01
10.28*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.01
10.29*	Forward Sale Agreement, dated Oct. 30, 2019, between Xcel Energy Inc. and Citibank, N.A.	Xcel Energy Inc. Form 8-K dated Oct. 30, 2019	001-03034	10.01
10.30*	Additional Forward Sale Agreement, dated Nov. 1, 2019 between Xcel Energy Inc. and Citibank, N.A.	Xcel Energy Inc. Form 8-K dated Oct. 30, 2019	001-03034	10.02
10.31*	364-Day Term Loan Agreement dated Dec. 3, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and Canadian Imperial Bank of Commerce, New York Branch, as Administrative Agent	Xcel Energy Inc. Form 8-K dated Dec. 3, 2019	001-03034	10.01
10.32+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan			
NSP-Minnesota				
4.13*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(3)
4.14*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.11
4.15*	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.12
4.16*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.51
4.17*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(7)

4.18*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.63
4.19*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due 2035	NSP-Minnesota Form 8-K dated July 14, 2005	001-31387	4.01
4.20*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due 2036	NSP-Minnesota Form 8-K dated May 18, 2006	001-31387	4.01
4.21*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	001-31387	4.01
4.22*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	001-31387	4.01
4.23*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	001-31387	4.01
4.24*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	001-31387	4.01
4.25*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due 2023	NSP-Minnesota Form 8-K dated May 20, 2013	001-31387	4.01
4.26*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due 2044	NSP-Minnesota Form 8-K dated May 13, 2014	001-31387	4.01
4.27*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	001-31387	4.01
4.28*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due 2046	NSP-Minnesota Form 8-K dated May 31, 2016	001-31387	4.01
4.29*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	001-31387	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2019 between Northern States Power Company and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 2.90% First Mortgage Bonds, Series due 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	001-31387	4.01
10.33*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01
10.34*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.02
NSP-Wisconsin				
4.31*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(c)(3)
4.32*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	001-03140	4.01
4.33*	Supplemental Trust Indenture dated as of Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991	Xcel Energy Inc Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.05
4.34*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	001-03140	4.01
4.35*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	001-03140	4.01
4.36*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	001-03140	4.01
4.37*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.75% First Mortgage Bonds, Series due 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	001-03140	4.01
4.38*	Supplemental Indenture dated as of Sept. 1, 2018 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 4.20% First Mortgage Bonds, Series due 2048	NSP-Wisconsin to Form 8-K dated Sept. 12, 2018	001-03034	4.01
10.35*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01

10.36*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.05
PSCo				
4.39*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(d)(3)
4.40*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 14, 1999 between PSCo and the Bank of New York	PSCo Form 8-K dated July 13, 1999	001-03280	4.1 4.2
4.41*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	001-03280	4.01
4.42*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series due 2038	PSCo Form 8-K dated Aug. 6, 2008	001-03280	4.01
4.43*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125% First Mortgage Bonds, Series due 2019	PSCo Form 8-K dated May 28, 2009	001-03280	4.01
4.44*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.20% First Mortgage Bonds, Series due 2020	PSCo Form 8-K dated Nov. 8, 2010	001-03280	4.01
4.45*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series due 2041	PSCo Form 8-K dated Aug. 9, 2011	001-03280	4.01
4.46*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series due 2042	PSCo Form 8-K dated Sept. 11, 2012	001-03280	4.01
4.47*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series due 2043	PSCo Form 8-K dated March 26, 2013	001-03280	4.01
4.48*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series due 2044	PSCo Form 8-K dated March 10, 2014	001-03280	4.01
4.49*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series due 2025	PSCo Form 8-K dated May 12, 2015	001-03280	4.01
4.50*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series due 2046	PSCo Form 8-K dated June 13, 2016	001-03280	4.01
4.51*	Supplemental Indenture dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series due 2047	PSCo Form 8-K dated June 19, 2017	001-03280	4.01
4.52*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series due 2048	PSCo Form 8-K dated June 21, 2018	001-03280	4.01
4.53*	Supplemental Indenture dated as of March 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 4.05% First Mortgage Bonds, Series due 2049	PSCo Form 8-K dated March 13, 2019	001-03280	4.01
4.54*	Supplemental Indenture dated as of Aug. 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $550 million principal amount of 3.20% First Mortgage Bonds, Series due 2050	PSCo Form 8-K dated August 13, 2019	001-03280	4.01
10.37*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	001-03034	99.02
10.38*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 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, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.03
SPS				
4.55*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.56*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.04
4.57*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	001-03789	4.01
4.58*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.01
4.59*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.60*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.61*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02
4.62*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug 9. 2017	001-03789	4.02
4.63*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	001-03789	4.02

4.64*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	001-03789	4.02
10.39*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.04
Xcel Energy Inc.				
21.01	Subsidiaries of Xcel Energy Inc.			
23.01	Consent of Independent Registered Public Accounting Firm			
24.01	Powers of Attorney			
31.01	Principal Executive Officer’s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
31.02	Principal Financial Officer’s certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002			
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document			
101.SCH	XBRL Schema			
101.CAL	XBRL Calculation			
101.DEF	XBRL Definition			
101.LAB	XBRL Label			
101.PRE	XBRL Presentation			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)			

SCHEDULE I

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

	Year Ended Dec. 31		
	2019	2018	2017
Income			
Equity earnings of subsidiaries	$ 1,505	$ 1,393	$ 1,263
Total income	1,505	1,393	1,263
Expenses and other deductions			
Operating expenses	23	24	30
Other income	(9)	(1)	(6)
Interest charges and financing costs	173	149	128
Total expenses and other deductions	187	172	152
Income before income taxes	1,318	1,221	1,111
Income tax benefit	(54)	(40)	(37)
Net income	$ 1,372	$ 1,261	$ 1,148
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $1, $1 and $3, respectively	$ 3	$ 3	$ 4
Derivative instruments, net of tax of $(7), $(1) and $2, respectively	(20)	(2)	3
Other comprehensive income (loss)	(17)	1	7
Comprehensive income	$ 1,355	$ 1,262	$ 1,155
Weighted average common shares outstanding:			
Basic	519	511	509
Diluted	520	511	509
Earnings per average common share:			
Basic	$ 2.64	$ 2.47	$ 2.26
Diluted	2.64	2.47	2.25

See Notes to Condensed Financial Statements

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

	Year Ended Dec. 31		
	2019	2018	2017
Operating activities			
Net cash provided by operating activities	$ 1,389	$ 1,210	$ 1,208
Investing activities			
Capital contributions to subsidiaries	(1,594)	(809)	(849)
Investments in the utility money pool	(1,054)	(2,578)	(1,258)
Return of investments in the utility money pool	1,093	2,493	1,173
Net cash used in investing activities	(1,555)	(894)	(934)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	12	(295)	715
Proceeds from issuance of long-term debt	1,120	492	—
Repayment of long-term debt	(550)	—	(250)
Proceeds from issuance of common stock	458	230	—
Repurchase of common stock	—	(1)	(3)
Dividends paid	(791)	(730)	(721)
Other	(14)	(12)	(14)
Net cash (used in) provided by financing activities	235	(316)	(273)
Net change in cash and cash equivalents	69	—	1
Cash and cash equivalents at beginning of period	1	1	—
Cash and cash equivalents at end of period	$ 70	$ 1	$ 1

See Notes to Condensed Financial Statements

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

	Dec. 31	
	2019	2018
Assets		
Cash and cash equivalents	$ 70	$ 1
Accounts receivable from subsidiaries	370	309
Other current assets	12	1
Total current assets	452	311
Investment in subsidiaries	17,443	15,965
Other assets	60	44
Total other assets	17,503	16,009
Total assets	$ 17,955	$ 16,320
Liabilities and Equity		
Dividends payable	212	195
Short-term debt	500	488
Other current liabilities	33	10
Total current liabilities	745	693
Other liabilities	23	32
Total other liabilities	23	32
Commitments and contingencies		
Capitalization		
Long-term debt	3,948	3,373
Common stockholders' equity	13,239	12,222
Total capitalization	17,187	15,595
Total liabilities and equity	$ 17,955	$ 16,320

See Notes to Condensed Financial Statements

Notes to Condensed Financial Statements

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

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

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

Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2019 and 2018, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2019:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of loan for Hiawatha Collegiate High School (a)	Xcel Energy Inc.	$ 1.0	—	(c)
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries (b)	Xcel Energy Inc.	60.4	(e)	(d)

(a) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.

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

(c) Nonperformance and/or nonpayment.

(d) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

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

Indemnification Agreements

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

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

	2019		2018	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 60	$ —	$ 117	$ —
NSP-Wisconsin	17	—	3	—
PSCo	78	—	29	—
SPS	47	—	39	—
Xcel Energy Services Inc.	112	—	96	—
Xcel Energy Ventures Inc.	25	—	13	—
Other subsidiaries of Xcel Energy Inc.	31	—	12	—
	$ 370	$ —	$ 309	$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $2,987 million, $1,097 million and $1,063 million for the years ended Dec. 31, 2019, 2018 and 2017, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

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

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2019
Loan outstanding at period end	$ 39
Average loan outstanding	35
Maximum loan outstanding	125
Weighted average interest rate, computed on a daily basis	1.67%
Weighted average interest rate at end of period	1.63%
Money pool interest income	1.47%

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Loan outstanding at period end	$ 39	$ —	$ 85
Average loan outstanding	47	71	38
Maximum loan outstanding	250	243	226
Weighted average interest rate, computed on a daily basis	2.15%	1.95%	1.13%
Weighted average interest rate at end of period	1.63%	N/A	1.18
Money pool interest income	$ 1.0	$ 1.4	$ 0.4

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

SCHEDULE II

Xcel Energy Inc. and Subsidiaries Valuation and Qualifying Accounts Years Ended Dec. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2019	2018	2017	2019	2018	2017
Balance at Jan. 1	$ 55	$ 52	$ 51	$ 79	$ 77	$ 58
Additions charged to costs and expenses	42	42	39	9	7	9
Additions charged to other accounts	16 (a)	11 (a)	10 (a)	—	—	22 (c)
Deductions from reserves	(58) (b)	(50) (b)	(48) (b)	(21) (e)	(5) (e)	(12) (d)
Balance at Dec. 31	$ 55	$ 55	$ 52	$ 67	$ 79	$ 77

(a) Recovery of amounts previously written off.

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

(c) Accrual of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability and includes $14 million expense related to the revaluation of federal benefit as a result of the TCJA.

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

(e) Primarily the reductions to valuation allowances due to additional NOLs and tax credits now forecasted to be used prior to expiration.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

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

		XCEL ENERGY INC.
Feb. 21, 2020	By:	/s/ ROBERT C. FRENZEL
		Robert C. Frenzel
		Executive Vice President, Chief Financial Officer
		(Principal Financial Officer)

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

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

SHAREHOLDER INFORMATION

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WEBSITE
xcelenergy.com

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EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
Telephone: 877.778.6786, toll free

REPORTS AVAILABLE ONLINE
Financial reports, including filings with the Securities and Exchange Commission and Xcel Energy's Report to Shareholders, are available online at xcelenergy.com; click on Investor Relations. Other information about Xcel Energy, including our Code of Conduct, Guidelines on Corporate Governance, Corporate Responsibility Report and Committee Charters, is also available at xcelenergy.com.

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL
Common stock is listed on the Nasdaq Global Select Market (Nasdaq) under the ticker symbol XEL. In newspaper listings, it appears as XcelEngy.

INVESTOR RELATIONS
Website: xcelenergy.com or contact Paul Johnson, Vice President, Investor Relations, at 612.215.4535.

SHAREHOLDER SERVICES
Website: xcelenergy.com or contact Darin Norman, Senior Analyst, Investor Relations, at 612.337.2310 or email darin.norman@xcelenergy.com.

CORPORATE GOVERNANCE
Xcel Energy has filed with the Securities and Exchange Commission certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2019. It has also filed with the New York Stock Exchange the CEO certification for 2019 required by section 303A.12(a) of the New York Stock Exchange's rules relating to compliance with the New York Stock Exchange's corporate governance listing standards.

To contact the Board of Directors, send an email to boardofdirectors@xcelenergy.com.

You also may direct questions to the Corporate Secretary's Department at corporatesecretary@xcelenergy.com.

The Xcel Energy Board of Directors (from left to right): Tim Wolf, Richard Davis, David Westerlund, Lynn Casey, Chris Policinski, David Owens, Ben Fowke, Kim Williams, Richard O'Brien, Daniel Yohannes, Jim Prokopanko, James Sheppard and Pat Sampson. Not pictured are new board members: Netha Johnson and George Kehl.

FISCAL AGENTS

XCEL ENERGY INC.

Transfer Agent, Registrar, Dividend Distribution, Common Stock
EQ Shareowner Services,
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120

Trustee–Bonds
Wells Fargo Bank, N.A.,
Corporate Trust Services
600 South 4th Street
Minneapolis, MN 55415

Xcel Energy®

Schedule Q-4

Reports to the Securities and Exchange Commission

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2019 Form 10-Q

For the Quarterly Period Ended September 30, 2019

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended Sept. 30, 2019 or

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

001-3034	75-0575400
(Commission File Number)	(I.R.S. Employer Identification No.)

(Registrant, State of Incorporation or Organization, Address of Principal Executive Officers and Telephone Number)

Southwestern Public Service Company

New Mexico

790 South Buchanan Street

Amarillo Texas 79101

303 571-7511

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

Title of each class	Trading Symbol	Name of each exchange on which registered
N/A	N/A	N/A

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

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

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

Large Accelerated Filer	☐	Accelerated Filer	☐
Non-accelerated Filer	☒	Smaller Reporting Company	☐
		Emerging growth company	☐

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

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

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

Class	Oct. 25, 2019
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

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This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS 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.

ABBREVIATIONS AND INDUSTRY TERMS

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

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Electric and Resource Adjustment Clauses

DSM	Demand side management
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause

Other Terms and Abbreviations

ACE	Affordable Clean Energy
ADIT	Accumulated deferred income tax
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
ATRR	Annual transmission revenue requirement
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
IPP	Independent power producers
NAV	Net asset value
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open access transmission tariff
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
ROU	Right-of-use
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
VIE	Variable interest entity

Measurements

MW	Megawatts
MWh	Megawatt hours

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Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, 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 Quarterly Report on Form 10-Q and in other securities filings (including SPS’ Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018, and subsequent securities filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: changes in environmental laws and regulations; climate change and other weather, natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; ability to recover costs from customers; reductions in our credit ratings and the costs of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers’ and counterparties’ ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

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PART 1 — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2019	2018	2019	2018
Operating revenues	$ 533.1	$ 540.1	$ 1,397.7	$ 1,468.6
Operating expenses				
Electric fuel and purchased power	240.2	284.0	651.0	795.6
Operating and maintenance expenses	74.1	71.5	216.6	203.7
Demand side management expenses	4.5	4.6	12.9	13.5
Depreciation and amortization	61.3	52.2	172.3	150.2
Taxes (other than income taxes)	17.6	16.8	53.1	50.0
Total operating expenses	397.7	429.1	1,105.9	1,213.0
Operating income	135.4	111.0	291.8	255.6
Other income (expense), net	1.5	(1.0)	2.4	(2.4)
Allowance for funds used during construction — equity	3.2	5.0	22.2	11.6
Interest charges and financing costs				
Interest charges — includes other financing costs of $0.9, $0.7, $2.5 and $2.1, respectively	26.0	21.0	76.0	61.8
Allowance for funds used during construction — debt	(1.5)	(2.2)	(10.2)	(5.5)
Total interest charges and financing costs	24.5	18.8	65.8	56.3
Income before income taxes	115.6	96.2	250.6	208.5
Income taxes	10.5	14.7	32.6	35.4
Net income	$ 105.1	$ 81.5	$ 218.0	$ 173.1

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2019	2018	2019	2018
Net income	$ 105.1	$ 81.5	$ 218.0	$ 173.1
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $0	—	0.1	0.1	0.1
Other comprehensive income	—	0.1	0.1	0.1
Comprehensive income	$ 105.1	$ 81.6	$ 218.1	$ 173.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Nine Months Ended Sept. 30, 2019	Nine Months Ended Sept. 30, 2018
Operating activities		
Net income	$ 218.0	$ 173.1
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	174.0	150.4
Demand side management program amortization	—	1.3
Deferred income taxes	16.2	14.4
Allowance for equity funds used during construction	(22.2)	(11.6)
Changes in operating assets and liabilities:		
Accounts receivable	(26.5)	(25.1)
Accrued unbilled revenues	(10.4)	9.6
Inventories	(16.3)	7.0
Prepayments and other	6.0	0.6
Accounts payable	(15.1)	(0.9)
Net regulatory assets and liabilities	17.6	58.8
Other current liabilities	14.1	13.0
Pension and other employee benefit obligations	(17.6)	(7.9)
Change in other noncurrent assets	0.7	3.5
Change in other noncurrent liabilities	1.3	(0.2)
Net cash provided by operating activities	339.8	386.0
Investing activities		
Utility capital/construction expenditures	(632.8)	(610.0)
Investments in utility money pool arrangement	(133.0)	(46.0)
Repayments from utility money pool arrangement	133.0	111.0
Net cash used in investing activities	(632.8)	(545.0)
Financing activities		
(Repayments of) Proceeds from short-term borrowings, net	(42.0)	35.0
Proceeds from issuance of long-term debt, net	292.2	—
Borrowings under utility money pool arrangement	283.0	446.0
Repayments under utility money pool arrangement	(283.0)	(423.0)
Capital contributions from parent	400.8	181.4
Dividends paid to parent	(255.0)	(90.7)
Net cash provided by financing activities	396.0	148.7
Net change in cash and cash equivalents	103.0	(10.3)
Cash and cash equivalents at beginning of period	44.0	10.9
Cash and cash equivalents at end of period	$ 147.0	$ 0.6
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (60.3)	$ (57.9)
Cash paid for income taxes, net	(4.4)	(15.3)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 67.5	$ 54.6
Inventory transfer additions in PPE	18.7	17.0
Operating lease right-of-use assets	548.3	—
Allowance for equity funds used during construction	22.2	11.6

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	Sept. 30, 2019	Dec. 31, 2018
Assets		
Current assets		
Cash and cash equivalents	$ 147.0	$ 44.0
Accounts receivable, net	113.9	90.7
Accounts receivable from affiliates	6.1	10.5
Accrued unbilled revenues	124.9	114.5
Inventories	31.4	33.9
Regulatory assets	20.8	26.0
Derivative instruments	20.4	17.8
Prepaid taxes	1.5	14.2
Prepayments and other	17.6	10.7
Total current assets	483.6	362.3
Property, plant and equipment, net	6,441.9	5,946.4
Other assets		
Regulatory assets	362.0	366.2
Derivative instruments	13.4	15.8
Operating lease right-of-use assets	529.0	—
Other	4.4	5.1
Total other assets	908.8	387.1
Total assets	$ 7,834.3	$ 6,695.8
Liabilities and Equity		
Current liabilities		
Short-term debt	$ —	$ 42.0
Accounts payable	168.3	191.8
Accounts payable to affiliates	14.9	19.9
Regulatory liabilities	116.8	85.8
Taxes accrued	51.5	41.6
Accrued interest	29.1	25.8
Dividends payable to parent	45.6	45.2
Derivative instruments	3.7	3.6
Other	53.0	28.3
Total current liabilities	482.9	484.0
Deferred credits and other liabilities		
Deferred income taxes	653.4	619.1
Regulatory liabilities	736.5	780.9
Asset retirement obligations	49.9	32.4
Derivative instruments	13.7	16.4
Pension and employee benefit obligations	75.2	92.4
Operating lease liabilities	502.2	—
Other	9.0	7.9
Total deferred credits and other liabilities	2,039.9	1,549.1
Commitments and contingencies		
Capitalization		
Long-term debt	2,419.3	2,126.1
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Sept. 30, 2019 and Dec. 31, 2018, respectively	—	—
Additional paid in capital	2,325.3	1,932.3
Retained earnings	568.2	605.7
Accumulated other comprehensive loss	(1.3)	(1.4)
Total common stockholder's equity	2,892.2	2,536.6
Total liabilities and equity	$ 7,834.3	$ 6,695.8

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended Sept. 30, 2019 and 2018						
Balance at June 30, 2018	100	$ —	$ 1,591.4	$ 569.2	$ (1.5)	$ 2,159.1
Net income				81.5		81.5
Other comprehensive income					0.1	0.1
Dividends declared to parent				(40.0)		(40.0)
Contributions of capital by parent			180.0			180.0
Balance at Sept. 30, 2018	100	$ —	$ 1,771.4	$ 610.7	$ (1.4)	$ 2,380.7
Balance at June 30, 2019	100	$ —	$ 2,307.3	$ 577.7	$ (1.3)	$ 2,883.7
Net income				105.1		105.1
Dividends declared to parent				(114.6)		(114.6)
Contributions of capital by parent			18.0			18.0
Balance at Sept. 30, 2019	100	$ —	$ 2,325.3	$ 568.2	$ (1.3)	$ 2,892.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Nine Months Ended Sept. 30, 2019 and 2018						
Balance at Dec. 31, 2017	100	$ —	$ 1,590.2	$ 541.6	$ (1.5)	$ 2,130.3
Net income				173.1		173.1
Other comprehensive income					0.1	0.1
Dividends declared to parent				(104.0)		(104.0)
Contributions of capital by parent	—	—	181.2			181.2
Balance at Sept. 30, 2018	100	$ —	$ 1,771.4	$ 610.7	$ (1.4)	$ 2,380.7
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6
Net income				218.0		218.0
Other comprehensive income					0.1	0.1
Dividends declared to parent				(255.5)		(255.5)
Contributions of capital by parent			393.0			393.0
Balance at Sept. 30, 2019	100	$ —	$ 2,325.3	$ 568.2	$ (1.3)	$ 2,892.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY

Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with U.S. GAAP, the financial position of SPS as of Sept. 30, 2019 and Dec. 31, 2018; the results of its operations, including the components of net income and comprehensive income, and change in stockholder's equity for the three and nine months ended Sept. 30, 2019 and 2018; and its cash flows for the nine months ended Sept. 30, 2019 and 2018. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2019 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2018 balance sheet information has been derived from the audited 2018 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2018. These notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto, included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2018, filed with the SEC on Feb. 22, 2019. Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2018, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after Dec. 15, 2019, and will be applied on a modified-retrospective approach through a cumulative-effect adjustment to retained earnings as of Jan. 1, 2020. SPS expects the impact of adoption of the new standard to include first-time recognition of expected credit losses (i.e., bad debt expense) on unbilled revenues, with the initial allowance established at Jan. 1, 2020 charged to retained earnings.

Recently Adopted

Leases — In 2016, the FASB issued *Leases*, *Topic 842 (ASC Topic 842)*, which provides new accounting and disclosure guidance for leasing activities, most significantly requiring that operating leases be recognized on the balance sheet. SPS adopted the guidance on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions on whether agreements existing before the adoption date contain leases and whether existing leases are operating or finance leases; ASC Topic 842 refers to capital leases as finance leases.

Specifically for land easement contracts, SPS has elected the practical expedient provided by *ASU No. 2018-01 Leases: Land Easement Practical Expedient for Transition to Topic 842*, and as a result, only those easement contracts entered on or after Jan. 1, 2019 will be evaluated to determine if lease treatment is appropriate.

SPS also utilized the transition practical expedient offered by *ASU No. 2018-11 Leases: Targeted Improvements* to implement the standard on a prospective basis. As a result, reporting periods in the financial statements beginning Jan. 1, 2019 reflect the implementation of ASC Topic 842, while prior periods continue to be reported in accordance with *Leases, Topic 840 (ASC Topic 840)*. Other than first-time recognition of operating leases on its balance sheet, the implementation of ASC Topic 842 did not have a significant impact on SPS' financial statements. Adoption resulted in recognition of approximately $0.5 billion of operating lease ROU assets and current/noncurrent operating lease liabilities. See Note 9 to the financial statements for leasing disclosures.

3. Selected Balance Sheet Data

(Millions of Dollars)	Sept. 30, 2019	Dec. 31, 2018
Accounts receivable, net		
Accounts receivable	$ 119.5	$ 96.3
Less allowance for bad debts	(5.6)	(5.6)
Accounts receivable, net	$ 113.9	$ 90.7

(Millions of Dollars)	Sept. 30, 2019	Dec. 31, 2018
Inventories		
Materials and supplies	$ 24.8	$ 25.7
Fuel	6.6	8.2
Total inventories	$ 31.4	$ 33.9

(Millions of Dollars)	Sept. 30, 2019	Dec. 31, 2018
Property, plant and equipment, net		
Electric plant	$ 8,296.6	$ 7,227.7
Construction work in progress	419.2	847.3
Total property, plant and equipment	8,715.8	8,075.0
Less accumulated depreciation	(2,273.9)	(2,128.6)
Property, plant and equipment, net	$ 6,441.9	$ 5,946.4

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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.

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Money pool borrowings for SPS were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2019	Year Ended Dec. 31, 2018
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	—
Average amount outstanding	—	29
Maximum amount outstanding	—	100
Weighted average interest rate, computed on a daily basis	N/A	1.96%
Weighted average interest rate at period end	N/A	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2019	Year Ended Dec. 31, 2018
Borrowing limit	$ 500	$ 400
Amount outstanding at period end	—	42
Average amount outstanding	—	30
Maximum amount outstanding	—	144
Weighted average interest rate, computed on a daily basis	N/A	2.27%
Weighted average interest rate at period end	N/A	2.80

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Sept. 30, 2019 and Dec. 31, 2018, there were $2 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, SPS 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 line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreement — In June 2019, SPS entered into an amended five-year credit agreement with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the exception of the following:

- Maturity extended from June 2021 to June 2024.
- Borrowing limit increased from $400 million to $500 million

SPS has the right to request an extension of the revolving credit facility termination date for two additional one year, periods. All extension requests are subject to majority bank group approval.

As of Sept. 30, 2019, SPS had the following committed credit facility available (in millions of dollars):

Credit Facility (a)	Outstanding (b)	Available
$ 500	$ 2	$ 498

(a) This credit facility expires in June 2024.

(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of Sept. 30, 2019 and Dec. 31, 2018.

Long-Term Borrowings

During the nine months ended Sept. 30, 2019, SPS issued $300 million of 3.75% first mortgage bonds due June 15, 2049.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consists of the following:

	Three Months Ended	
(Millions of Dollars)	Sept. 30, 2019	Sept. 30, 2018
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 119.3	$ 114.4
C&I	222.4	229.4
Other	12.8	13.0
Total retail	354.5	356.8
Wholesale	106.6	118.0
Transmission	64.4	60.7
Other	0.6	1.8
Total revenue from contracts with customers	526.1	537.3
Alternative revenue and other	7.0	2.8
Total revenues	$ 533.1	$ 540.1

	Nine Months Ended	
(Millions of Dollars)	Sept. 30, 2019	Sept. 30, 2018
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 277.8	$ 279.5
C&I	619.6	626.0
Other	32.3	34.0
Total retail	929.7	939.5
Wholesale	263.4	326.8
Transmission	181.8	175.4
Other	2.0	12.2
Total revenue from contracts with customers	1,376.9	1,453.9
Alternative revenue and other	20.8	14.7
Total revenues	$ 1,397.7	$ 1,468.6

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6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2018 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

The following table reconciles the difference between the statutory rate and the ETR:

	Nine Months Ended Sept. 30, 2019	Nine Months Ended Sept. 30, 2018
Federal statutory rate	21.0%	21.0%
State tax (net of federal tax effect)	2.2	2.3
Decreases in tax from:		
Plant regulatory differences [a]	(4.7)	(3.8)
Wind PTCs	(3.9)	—
Other tax credits and tax credit and NOL allowances (net)	(0.6)	(0.7)
Prior period adjustments	(0.5)	(1.8)
Other (net)	(0.5)	—
Effective income tax rate	13.0%	17.0%

[a] Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method and the timing of regulatory decisions regarding the return of excess deferred taxes. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

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

Tax Year(s)	Expiration
2009 - 2013	June 2020
2014 - 2016	September 2020

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Sept. 30, 2019, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of Sept. 30, 2019 no adjustments have been proposed.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Sept. 30, 2019, SPS' earliest open tax year 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 Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	Sept. 30, 2019	Dec. 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 3.5	$ 3.0
Unrecognized tax benefit — Temporary tax positions	1.5	1.5
Total unrecognized tax benefit	$ 5.0	$ 4.5

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

(Millions of Dollars)	Sept. 30, 2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (4.4)	$ (3.8)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $1.4 million and $0.8 million at Sept. 30, 2019 and Dec. 31, 2018, respectively.

As the IRS Appeals and federal audit progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.7 million in the next 12 months.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2019 or Dec. 31, 2018.

7. 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, hierarchical framework for measuring assets and liabilities and requires disclosure about assets and liabilities measured at fair value.

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

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

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

Specific valuation methods include:

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

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 generally utilize observable forward prices and volatilities, as well as observable pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to delivery locations for which pricing is relatively unobservable, or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable inputs on a valuation is evaluated, and may result in Level 3 classification.

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of Sept. 30, 2019, accumulated other comprehensive loss related to interest rate derivatives included $0.1 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 — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

(Amounts in Millions) [(a)]	Sept. 30, 2019	Dec. 31, 2018
Mwh of electricity	9.4	5.5

(a) Amounts are not reflective of net positions in the underlying commodities.

Consideration of Credit Risk and Concentrations — SPS continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets. SPS' 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 Sept. 30, 2019, one of the six most significant counterparties for these activities, comprising $14.2 million or 31% of this credit exposure, had investment grade ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Five of the six most significant counterparties, comprising $9.7 million or 21% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. Six of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial for the three and nine months ended Sept. 30, 2019 and 2018.

Changes in the fair value of FTRs resulting in immaterial pre-tax net gains and pre-tax net gains of $4.7 million were recognized for the three and nine months ended Sept. 30, 2019, respectively, were reclassified as regulatory assets and liabilities. For the three and nine months ended Sept. 30, 2018, changes in the fair value of FTRs resulted in pre-tax net losses of $3.3 million and pre-tax net gains of $10.1 million, respectively, and were recognized as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains of $1.7 million and $1.5 million were recognized for the three and nine months ended Sept. 30, 2019, respectively, and were recorded to electric fuel and purchased power. There were immaterial FTR settlement losses and $3.4 million of FTR settlement gains recognized for the three and nine months ended Sept. 30, 2018, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2019 and 2018.

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

	Sept. 30, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 17.3	$ 17.3	$ —	$ 17.3	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	$ 14.7
Total current derivative assets	$ —	$ —	$ 17.3	$ 17.3	$ —	17.3	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	14.7
PPAs [(b)]						3.1						3.1
Current derivative instruments						$ 20.4						$ 17.8
Noncurrent derivative assets												
PPAs [(b)]						13.4						15.8
Noncurrent derivative instruments						$ 13.4						$ 15.8
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.2	$ 0.2	$ —	$ 0.2	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —
Total current derivative liabilities	$ —	$ —	$ 0.2	$ 0.2	$ —	0.2	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—
PPAs [(b)]						3.5						3.6
Current derivative instruments						$ 3.7						$ 3.6
Noncurrent derivative liabilities												
PPAs [(b)]						13.7						16.4
Noncurrent derivative instruments						$ 13.7						$ 16.4

(a) SPS nets derivative instruments and related collateral in its 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 Sept. 30, 2019 and Dec. 31, 2018. At both Sept. 30, 2019 and Dec. 31, 2018, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS 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.

Changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2019 and 2018:

	Three Months Ended Sept. 30,	
(Millions of Dollars)	2019	2018
Balance at July 1	$ 22.2	$ 35.4
Purchases	4.4	3.2
Settlements	(5.2)	(10.1)
Net transactions recorded during the period:		
Net losses recognized as regulatory assets and liabilities	(4.3)	(3.2)
Balance at Sept. 30	$ 17.1	$ 25.3

	Nine Months Ended Sept. 30,	
(Millions of Dollars)	2019	2018
Balance at Jan. 1	$ 14.7	$ 12.7
Purchases	25.5	22.5
Settlements	(24.9)	(35.3)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	1.8	25.4
Balance at Sept. 30	$ 17.1	$ 25.3

SPS recognizes transfers between fair value hierarchy levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2019 and 2018.

Fair Value of Long-Term Debt

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

	Sept. 30, 2019		Dec. 31, 2018	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 2,419.3	$ 2,763.2	$ 2,126.1	$ 2,139.8

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Sept. 30, 2019 and Dec. 31, 2018, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

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8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30			
	2019	2018	2019	2018
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2.2	$ 2.4	$ 0.2	$ 0.3
Interest cost [a]	5.0	4.6	0.4	0.4
Expected return on plan assets [a]	(7.1)	(7.1)	(0.5)	(0.6)
Amortization of prior service credit [a]	—	—	(0.1)	(0.1)
Amortization of net loss (gain) [a]	2.8	3.5	(0.1)	(0.1)
Net periodic benefit cost (credit)	2.9	3.4	(0.1)	(0.1)
Credits (costs) not recognized due to the effects of regulation	0.5	(0.4)	—	—
Net benefit cost (credit) recognized for financial reporting	$ 3.4	$ 3.0	$ (0.1)	$ (0.1)

	Nine Months Ended Sept. 30			
	2019	2018	2019	2018
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 6.6	$ 7.3	$ 0.7	$ 0.8
Interest cost [a]	15.1	13.8	1.3	1.2
Expected return on plan assets [a]	(21.5)	(21.2)	(1.5)	(1.8)
Amortization of prior service credit [a]	(0.1)	(0.1)	(0.4)	(0.3)
Amortization of net loss (gain) [a]	8.5	10.5	(0.3)	(0.3)
Net periodic benefit cost (credit)	8.6	10.3	(0.2)	(0.4)
Credits not recognized due to the effects of regulation	1.3	1.3	—	—
Net benefit cost (credit) recognized for financial reporting	$ 9.9	$ 11.6	$ (0.2)	$ (0.4)

(a) The components of net periodic cost other than the service cost component are included in the line item “other expense, net” in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2019, contributions of $150.0 million were made across four of Xcel Energy’s pension plans, of which $16.5 million was attributable to SPS. In July 2019, Xcel Energy made a $4.0 million contribution to the Xcel Energy Inc. Non-Bargaining Pension Plan (South), of which $1.2 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2019.

9. Commitments and Contingencies

The following include commitments, contingencies and unresolved contingencies that are material to SPS’ financial position.

Legal

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS’ financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

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

In July 2018, SPS’ appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund the charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for rehearing. The timing of a FERC response to the rehearing requests is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS’ complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC. facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP’s proposed tariff changes resulted in an increase in the ATRR of $9.5 million per year, with $6 million allocated to SPS’ retail customers. The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone.

In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On Oct. 31, 2018, the FERC issued an order accepting the proposed charges, subject to refund, as of Nov. 1, 2018, and set the case for settlement hearing procedures. Hearings are scheduled for May 2020, with the ALJ’s initial decision expected in October 2020.

SPS Filing to Modify Wholesale Transmission Rates — In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to the depreciation rates for transmission plant. The new formula rate would also provide a credit to customers of “excess” ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

The proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total being recovered in SPP regional transmission rates. SPS proposed that the formula rate changes be effective Feb. 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of Feb. 1, 2019, subject to refund and settlement procedures. Settlement procedures started in February 2019, and are ongoing.

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Environmental

MGP, Landfill or Disposal Sites — SPS is currently remediating the site of a former facility.

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

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under ASC Topic 842, adopted by SPS on Jan. 1, 2019, a contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent SPS' rights to use leased assets. Starting in 2019, the present value of future operating lease payments are recognized in other current liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of SPS' leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is calculated using the estimated incremental borrowing rate (weighted-average of 4.4%). SPS has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure. Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Sept. 30, 2019
PPAs	$ 500.3
Other	48.0
Gross operating lease ROU assets	548.3
Accumulated amortization	(19.3)
Net operating lease ROU assets	$ 529.0

Components of lease expense:

(Millions of Dollars)	Three Months Ended Sept. 30, 2019	Nine Months Ended Sept. 30, 2019
Operating leases		
PPA capacity payments	$ 11.4	$ 36.8
Other operating leases [(a)]	1.2	3.7
Total operating lease expense [(b)]	$ 12.6	$ 40.5

(a) Includes short-term lease expense of $0.3 million for the three months ended Sept. 30, 2019 and $1.2 million for the nine months ended Sept. 30, 2019.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense.

Future commitments under operating leases as of Sept. 30, 2019:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 11.6	$ 0.8	$ 12.4
2020	46.2	3.4	49.6
2021	46.2	3.3	49.5
2022	46.2	3.4	49.6
2023	46.2	3.4	49.6
Thereafter	450.8	54.8	505.6
Total minimum obligation	647.2	69.1	716.3
Interest component of obligation	(165.3)	(22.0)	(187.3)
Present value of minimum obligation	481.9	47.1	529.0
Less current portion			(26.8)
Noncurrent operating lease liabilities			$ 502.2
Weighted-average remaining lease term in years			14.3

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

Future commitments under operating leases as of Dec. 31, 2018:

(Millions of Dollars)	PPA [(a) (b)] Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 46.7	$ 5.2	$ 51.9
2020	46.2	5.2	51.4
2021	46.2	5.1	51.3
2022	46.2	5.1	51.3
2023	46.2	5.1	51.3
Thereafter	450.8	56.3	507.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

Variable Interest Entities

Under certain PPAs, SPS purchases power from IPPs and is required to reimburse the IPPs for fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that it purchases. These specific PPAs create a variable interest in the associated IPP.

SPS had approximately 1,197 MW of capacity under long-term PPAs as of Sept. 30, 2019 and Dec. 31, 2018, with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that significantly impact the entities' economic performance. These agreements have expiration dates through 2041.

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

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

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Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as, electric margin and ongoing earnings. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP. SPS's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Electric Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Management uses these non-GAAP financial measures to evaluate and provide details of SPS' core earnings and underlying performance.

For the three and nine months ended Sept. 30, 2019 and 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings for these periods.

Results of Operations

SPS' net income was approximately $218.0 million for the nine months ended Sept. 30, 2019 compared with approximately $173.1 million for the prior year. The increase reflects higher electric margin attributable to regulatory rate outcomes and sales growth despite unfavorable weather. Higher electric margin and AFUDC associated with the Hale Wind farm were partially offset by increased depreciation, O&M and interest expenses.

Electric Margin

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power.

Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2019	2018
Electric revenues	$ 1,397.7	$ 1,468.6
Electric fuel and purchased power	(651.0)	(795.6)
Electric margin	$ 746.7	$ 673.0

Changes in electric margin:

(Millions of Dollars)	2019 vs 2018
Purchased capacity costs	$ 31.9
Regulatory rate outcomes	23.7
Demand revenue	19.2
Wholesale transmission, net	14.5
Non-fuel riders	9.8
Retail sales growth	3.4
Firm wholesale	(16.9)
PTC sharing	(4.4)
Estimated weather impact	(4.2)
Other, net	(3.3)
Total increase in electric margin	$ 73.7

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses increased $12.9 million, or 6.3%, for the nine months ended Sept. 30, 2019 compared with the prior year. The increase was primarily driven by plant generation, distribution and business system expenses. Plant generation expenses increased due to timing of planned maintenance and overhauls. Distribution expenses increased as a result of additional pole inspections. Business system costs increased due to additional consulting fees.

Depreciation and Amortization — Depreciation and amortization increased $22.1 million, or 14.7%, for the nine months ended Sept. 30, 2019 compared with the prior year. The increase was primarily due to increased capital investments as well as accelerated depreciation at Tolk generating facility for the Texas jurisdiction.

AFUDC, Equity and Debt — AFUDC increased $15.3 million, for the nine months ended Sept. 30, 2019 compared with the prior year. The increase was primarily due to an increase in wind construction projects, primarily the Hale Wind farm.

Interest Charges — Interest charges increased $14.2 million, or 23.0%, for the nine months ended Sept. 30, 2019 compared with the prior year. The increase was related to higher debt levels to fund capital investments, changes in short-term interest rates and implementation of lease accounting standard (offset in electric margin).

Income Taxes — Income tax expense decreased $2.8 million for the nine months ended Sept. 30, 2019 compared with the prior year. The decrease was primarily driven by an increase in wind PTCs and an increase in plant-related regulatory differences. This was partially offset by higher pretax earnings. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. ETR was 13.0%, for the nine months ended Sept. 30, 2019 compared with 17.0% for the prior year, largely due to the items referenced above. See Note 6 to the financial statements.

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Public Utility Regulation

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 1 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2018 and in Item 2 of SPS' Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2019 and June 30, 2019, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

FERC and State Regulation — The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters.

Xcel Energy, which includes SPS, 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 Commodity Futures Trading Commission jurisdictions.

Public campaigns are conducted to raise awareness of public safety issues of interacting with our electric systems.

While programs to comply with regulatory requirements are in place, there is no guarantee compliance programs or other measures will be sufficient to ensure against violations. Decisions by these regulators can significantly impact SPS' results of operations.

Pending Regulatory Proceedings

2019 Texas Rate Case — In August 2019, SPS filed an electric rate case with the PUCT seeking an increase in retail electric base rates of approximately $141 million. The filing requests an ROE of 10.35%, a 54.65% equity ratio, a rate base of approximately $2.6 billion and is built on a 12 month period that ended June 30, 2019. In September 2019, SPS filed an update to the electric rate case and revised its requested increase to approximately $136 million.

The following table summarizes SPS' base rate increase request:

Revenue Request (Millions of Dollars)	
Hale Wind Farm	$ 62
Capital investments	47
Depreciation rate change (including Tolk)	34
Cost of capital	10
Expiring purchased power contracts	(28)
Other, net	11
New revenue request	$ 136

The procedural schedule is as follows:

- Intervenor testimony — Feb. 10, 2020
- Staff testimony — Feb. 18, 2020
- Rebuttal testimony — March 11, 2020
- Public hearing begins — March 30, 2020
- Final order deadline — Sept. 7, 2020

The final rates established at the end of the rate case are expected to be made effective relating back to Sept. 12, 2019. SPS expects a decision from the PUCT in the second quarter of 2020.

2019 New Mexico Rate Case — In July 2019, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $51 million. The rate request is based on a ROE of 10.35%, a 54.77% equity ratio, a rate base of approximately $1.3 billion and a historic test year with rate base additions through Aug. 31, 2019. SPS anticipates final rates will go into effect in the second or third quarter of 2020.

SPS' proposed increase in base rates would be partially mitigated by savings to New Mexico customers achieved through fuel cost reductions and PTCs attributable to wind energy provided by the Hale Wind Farm. SPS' $51 million requested increase in base rates would be offset by approximately $25 million of savings resulting in a net revenue increase of approximately $26 million, or 5.7%.

The following table summarizes SPS' base rate increase request:

Revenue Request (Millions of Dollars)	
Hale Wind Farm	$ 28
Other plant investment	22
Wholesale sales reduction	17
Allocator changes due to load growth	15
Depreciation rate change (including Tolk)	15
Base rate sales growth	(41)
Other, net	(5)
New revenue request	$ 51

The procedural schedule is as follows:

- Filing of stipulation, if any — Nov. 15, 2019
- Staff and intervenor testimony or testimony in support of a stipulation — Nov. 22, 2019
- Testimony in opposition to a stipulation, if any — Dec. 6, 2019
- Rebuttal testimony — Dec. 20, 2019
- Public hearing begins — Jan. 7, 2020
- End of 9-month suspension — April 30, 2020

Wind Development — In 2018, the NMPRC and PUCT approved SPS' proposal to add 1,230 MW of new wind generation, including construction and ownership of the 478 MW Hale and 522 MW Sagamore wind farms. The Hale wind farm was placed into commercial operation in June 2019. Sagamore is expected to go into service in 2020 and cost approximately $900 million.

Texas State Right of First Refusal (ROFR) Litigation — In May 2019, the Governor signed into law Senate Bill 1938, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional.

Texas Fuel Reconciliation — In December 2018, SPS filed an application with the PUCT for reconciliation of fuel costs for the period Jan. 1, 2016, through June 30, 2018, to determine whether all fuel costs incurred were eligible for recovery. On Oct. 17, 2019, the assigned Administrative Law Judges (ALJs) issued a Proposal for Decision recommending the PUCT disallow approximately $3 million of costs related to the reconciliation period, based on the ALJs' determination that entering into two specific solar PPAs was imprudent. The related solar facilities are located in New Mexico and were previously approved by the NMPRC as reasonable, necessary and economic. SPS plans to file exceptions regarding the proposed disallowance and assert, among other points, that the ALJs erred in failing to account for the capacity value of the solar projects.

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New Mexico Fuel Continuation — In October 2019, SPS filed an application to the NMPRC to approve SPS' continued use of its FPPCAC and for reconciliation of fuel costs for the period Sept. 1, 2015, through June 30, 2019, which will determine whether all fuel costs incurred are eligible for recovery. No procedural schedule has yet been established for this matter.

Environmental Matters

In June 2019, the EPA issued the final ACE rule to replace the Obama-era Clean Power Plan. The final ACE rule may require implementation of heat rate improvement projects at some of our coal-fired power plants. It is not known what the costs associated with the final rule might be until state plans are developed to implement the final regulation. SPS believes the costs would be recoverable through rates based on prior state commission practice.

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure. As of Sept. 30, 2019, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

Part II — OTHER INFORMATION

Item 1 — Legal Proceedings

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

Item 1A — RISK FACTORS

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2018, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

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Item 6 — EXHIBITS

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

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	001-03789	3.01
3.02*	By-Laws of SPS as Amended and Restated on Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	001-03789	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	XBRL Schema			
101.CAL	XBRL Calculation			
101.DEF	XBRL Definition			
101.LAB	XBRL Label			
101.PRE	XBRL Presentation			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)			

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SIGNATURES

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

Southwestern Public Service Company

Oct. 25, 2019

By: /s/ JEFFREY S. SAVAGE

Jeffrey S. Savage
Senior Vice President, Controller
(Principal Accounting Officer)

/s/ ROBERT C. FRENZEL

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

2019 Form 10-K
For the Fiscal Year Ended
December 31, 2019

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2019
or

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

001-03789
(Commission File Number)

SOUTHWESTERN PUBLIC SERVICE COMPANY
(Exact name of registrant as specified in its charter)

New Mexico	75-0575400
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
790 South Buchanan Street, Amarillo, Texas	79101
(Address of Principal Executive Offices)	(Zip Code)

(303) 571-7511
(Registrant's Telephone Number, Including Area Code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
N/A	N/A	N/A

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act.
☐ Large accelerated Filer ☐ Accelerated Filer ☒ Non-accelerated Filer ☐ Smaller Reporting Company ☐ Emerging Growth Company

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

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

As of Feb. 21, 2020, 100 shares of common stock, par value $1.00 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 2020 Annual Meeting of Shareholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 6, 2020. Such information set forth under such heading is incorporated herein by this reference hereto.

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

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

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PART I

ITEM I — BUSINESS

Definitions of Abbreviations

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

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NPRM	Notice of Proposed Rulemaking
PHMSA	Pipeline and Hazardous Materials Safety Administration
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric and Resource Adjustment Clauses

DCRF	Distribution cost recovery factor
DSM	Demand side management
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
FPPCAC	Fuel and purchased power cost adjustment clause
PCRF	Power cost recovery factor
RPS	Renewable portfolio standards
TCRF	Transmission cost recovery factor (recovers transmission infrastructure improvement costs and changes in wholesale transmission charges)

Other

ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
CEO	Chief executive officer
CFO	Chief financial officer
C&I	Commercial and Industrial
Corps	U.S. Army Corps of Engineers
CWIP	Construction work in progress
DSM	Demand side management
ELG	Effluent limitations guidelines
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IM	Integrated Marketplace
IPP	Independent power producing entity
IRP	Integrated Resource Plan
ITC	Investment tax credit
MGP	Manufactured gas plant
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
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
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right-of-first-refusal
ROU	Right-of-use
RTO	Regional Transmission Organization
SERP	Supplemental executive retirement 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
VIE	Variable interest entity

Measurements

KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours
ppb	Parts per billion

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Forward-Looking Statements

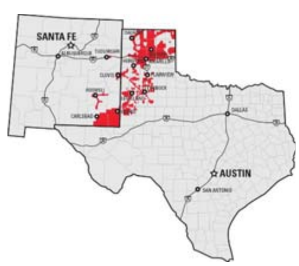
Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2019 (including risk factors listed from time to time by SPS in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs, changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

Where to Find More Information

SPS is a wholly owned subsidiary of Xcel Energy Inc., and Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov.

Company Overview

Electric customers	0.4 million
Total assets	$7.9 billion
Rate base	$4.9 billion
ROE	9.71%
Electric generating capacity	4,804 MW
Electric transmission lines (conductor miles)	38,418 miles
Electric distribution lines (conductor miles)	21,810 miles

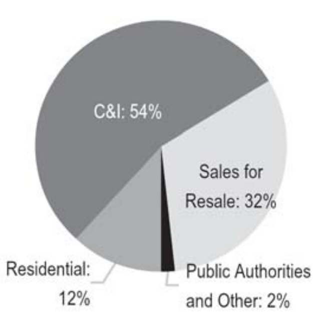


SPS was incorporated in 1921 under the laws of New Mexico. SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

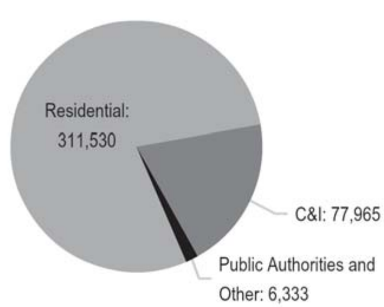
Electric Operations

SPS had electric sales volume of 30,894 (millions of KWh), 395,828 customers and electric revenues of $1,825.8 (millions of dollars) for 2019.

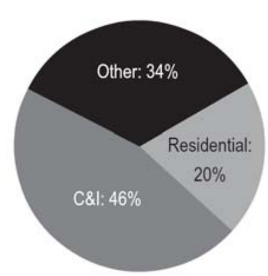
Sales Volume



Number of Customers



Revenues



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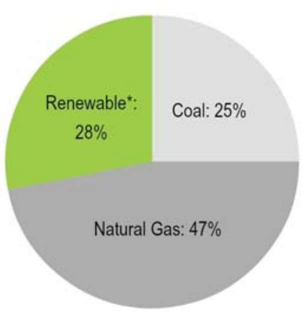
Sales/Revenue Statistics

	2019	2018
KWH sales per retail customer	53,123	52,074
Revenue per retail customer	$3,147	$3,124
Residential revenue per KWh	10.04¢	9.92¢
Large C&I revenue per KWh	4.01¢	4.08¢
Small C&I revenue per KWh	7.17¢	7.22¢
Total retail revenue per KWh	5.92¢	6.00¢

Owned and Purchased Energy Generation — 2019

Electric Energy Sources

Total electric generation by source (including energy market purchases) for the year ended Dec. 31, 2019:



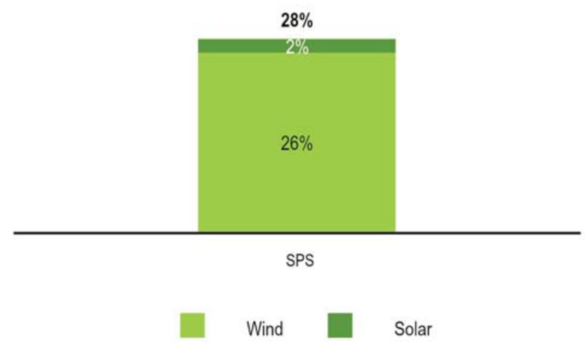
*Distributed generation from the Solar*Rewards® program is not included (approximately 12.9 million KWh for 2019).

Renewable Energy Sources

SPS' renewable energy portfolio includes wind and solar power from both owned generating facilities and PPAs. Renewable percentages will vary year over year based on system additions, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Renewable energy as a percentage of total energy for 2019:



(a) Includes biomass and hydroelectric.

Wind Energy Sources

Owned — Owned and operated wind farms with corresponding capacity:

2019		2018	
Wind Farms	Capacity	Wind Farms	Capacity
1	478 MW	—	—

PPAs — Number of PPAs with range:

2019		2018	
PPAs	Range	PPAs	Range
18	0.7 MW - 250.0 MW	18	0.7 MW - 250.0 MW

Capacity — Wind capacity:

2019	2018
2,045 MW	1,565 MW

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

2019	2018
$25	$26

Wind Energy Development

SPS placed approximately 460 MW of wind into service during 2019:

Project	Capacity
Hale	460 MW

SPS currently has approximately 522 MW of wind under development or construction with an estimated completion date of 2020:

Project	Capacity	Estimated Completion
Sagamore	522 MW	2020

Solar Energy Sources

Solar energy PPAs:

Type	Capacity
Distributed Generation	10 MW
Utility-Scale	191 MW

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Fossil Fuel Energy Sources

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

See Item 2 — Properties for further information.

Coal Energy Sources

SPS has two coal plants with approximately 2,100 MW of total 2019 net summer dependable capacity.

SPS plans to continue to evaluate its coal fleet for other potential early coal plant retirements as part of state resource plans or other regulatory proceedings.

Coal Fuel Cost

Delivered cost per MMBtu of coal consumed for owned electric generation and percentage of total fuel requirements:

	Coal	
	Cost	Percent
2019	$ 2.19	45%
2018	2.04	56

Natural Gas Energy Sources

SPS has eight natural gas plants with approximately 2,300 MW of total 2019 net summer dependable capacity.

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

Natural Gas Cost

Delivered cost per MMBtu of natural gas consumed for owned electric generation and percentage of total fuel requirements:

	Natural Gas	
	Cost	Percent
2019	$ 1.14	55%
2018	2.24	44

Capacity and Demand

Uninterrupted system peak demand and occurrence date:

System Peak Demand (in MW)			
2019		2018	
4,261	Aug. 5	4,648	July 19

Transmission

Transmission lines deliver electricity over long distances from power sources to transmission substations closer to homes and businesses. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support a diverse generation mix, including renewable energy. SPS owns more than 38,400 conductor miles of transmission lines across its service territory.

During 2019, SPS completed the following transmission projects:

Project	Miles	Size
TUCO-Yoakum-Hobbs	64	345 KV
NEF-Cardinal	15	115 KV
Potash Junction-Livingston Ridge	15	115 KV
Mustang-Shell	9	115 KV
North Loving-South Loving	3	115 KV
Cunningham-Monument Tap	7	115 KV

Upcoming transmission projects:

Project	Miles	Size	Completion Date
TUCO-Yoakum-Hobbs	106	345 KV	2020
Eddy-Kiowa	34	345 KV	2020

Public Utility Regulation

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body	Additional Information on Regulatory Authority
PUCT	Retail electric operations, rates, services, construction of transmission or generation and other aspects of electric operations. Texas municipalities have original jurisdiction over rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.
NMPRC	Retail electric operations, rates services, construction of transmission or generation and other aspects of electric operations.
FERC	Wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce.
SPP RTO and SPP IM Wholesale Market	SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Recovery Mechanisms

Mechanism	Additional Information
DCRF	Recovers distribution costs not included in rates in Texas.
EECRF	Recovers costs for energy efficiency programs in Texas.
EE Rider	Recovers costs for energy efficiency programs in New Mexico.
FPPCAC	Adjusts monthly to recover fuel and purchased power costs in New Mexico.
PCRF	Allows recovery of purchased power costs not included in Texas rates.
RPS	Recovers deferred costs for renewable energy programs in New Mexico.
TCRF	Recovers transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Fixed Fuel and Purchased Recovery Factor	Provides for recovery of energy expenses. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers production, fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Resource Plan

In December 2018, the NMPRC issued a final order accepting SPS' IRP.

SPS is forecasting a surplus capacity of 382 MW in 2028, but a capacity deficit of approximately 2,896 MW in 2038. SPS' optimal resource plan for the planning period incorporates the addition of wind, simple cycle combustion turbine generation, combined cycle energy and entering PPAs. Various factors may impact this IRP, which could potentially require updates to the action plan and will be the subject of future IRPs, including:

- New and revised environmental regulations;
- Impacts of variability due to participation in the SPP;
- Customer expectations;
- Technological advances;
- Groundwater aquifer depletion at SPS' Tolk Station;
- Aging generation fleet;
- Load growth and gas price variability;
- Changes to tax credits and incentives; and
- Changes to renewable portfolio standard acquisitions.

SPS is required to file an IRP in New Mexico every three years and will file its next IRP in July 2021.

Purchased Power Arrangements and Transmission Service Providers

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

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

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

Natural Gas

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

Wholesale and Commodity Marketing Operations

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

General

Seasonality

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

Competition

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

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

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

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. SPS' wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems of Xcel Energy Inc.'s utility subsidiaries on a comparable basis to serve their native load.

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

SPS has franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power, such as municipalization. No municipalization activities are occurring presently.

While facing these challenges, SPS believes its rates and services are competitive with alternatives currently available.

Environmental

Environmental Regulation

Our facilities are regulated by federal and state environmental agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. SPS has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems.

Our facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have.

We may be required to incur capital expenditures in the future for remediation of MGP and other sites if it is determined that prior compliance efforts are not sufficient.

There are significant present and future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. SPS has undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals.

If future environmental regulations do not take into consideration investments already made or if additional initiatives or emission reductions are required, substantial costs may be incurred.

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans for GHG reductions from coal-fired power plants. The state plans, due to the EPA in July 2022, will evaluate and potentially require heat rate improvements at existing coal-fired plants. It is not yet known how these state plans will affect SPS' existing coal plants, but they could require substantial additional investment, even in plants slated for retirement. SPS believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

SPS seeks to address climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner.

Employees

As of Dec. 31, 2019, SPS had 1,158 full-time employees and no part-time employees, of which 779 were covered under collective-bargaining agreements.

ITEM 1A — RISK FACTORS

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

Oversight of Risk and Related Processes

The Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of key risks.

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

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

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

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

Overall, the oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of SPS. Processes are in place to ensure appropriate risk oversight, as well as identification and consideration of new risks.

Risks Associated with Our Business

Operational Risks

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

Our natural gas transmission activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages. These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses. We maintain insurance against some, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows.

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

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

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

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

In addition, the long-term nature of both our planning and our asset lives are subject to risk. The electric utility sector is undergoing a period of significant change. For example, increases in energy efficiency, wider adoption of lower cost renewable generation, distributed generation and shifts away from coal generation to decrease carbon emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, as well as stranded costs if SPS is not able to fully recover costs and investments.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure, which increases exposure to technology obsolescence.

Evolving stakeholder preference for lower emission generation sources may pressure our investments in natural gas generation and delivery. The magnitude and timing of resource additions and changes in customer demand may not coincide while customer preference for resource generation may change, which introduces further uncertainty into long-term planning. Additionally, multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We are subject to longer-term availability of 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.

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

In the event fuel costs increase, customer demand could decline and bad debt expense may rise, which may have a material impact on our results of operations. Despite existing fuel 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 could impact our cash flows.

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

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

Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

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

Certain specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets. Our business strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees is high in the areas of business operations. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. We have seen a tightening of supply for engineers and skilled laborers in certain markets and are implementing plans to retain these employees. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

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

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

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 or Directors 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 2019, 2018 and 2017 we paid $332.7 million, $131.0 million and $108.8 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 SPS is imposed by its state regulatory commissions. State regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc., by requiring a minimum equity-to-total capitalization ratio.

See Note 5 to the financial statements for further information.

Financial Risks

Our profitability depends on our ability to recover costs from our customers and changes in regulation may impair our ability to recover costs from our customers.

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

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

There can also be no assurance that our regulatory commissions will judge all our costs to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery. Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair our ability to recover costs historically collected from customers, or we could exceed caps on capital costs (e.g., wind projects) required by commissions and result in less than full recovery.

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

In a continued low interest rate environment there has been increased downward pressure on allowed ROE. Conversely, higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that we will not be able to fully recover our fuel costs from our customers.

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

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

We cannot be assured that our current ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, significantly lower returns on equity, changes to equity ratios and impacts of tax policy 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 contracts that require 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. Capital markets are global and impacted by issues and events throughout the world. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

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 may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as SPP, PJM Interconnection, LLC, Midcontinent Independent System Operator, Inc. and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants.

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

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 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, 2019, Xcel Energy Inc. and its utility subsidiaries had approximately $17.4 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, 2019, Xcel Energy had guarantees outstanding with a maximum stated amount of approximately $2.0 million and immaterial exposure. Xcel Energy also had additional guarantees of $60.4 million at Dec. 31, 2019 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.

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

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high numbers of retirements or employees leaving would trigger settlement accounting and could require SPS to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs.

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

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

Federal tax law may significantly impact our business.

SPS collects through regulated rates estimated federal, state and local tax payments. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. There could be timing delays before regulated rates provide for realization of tax changes in revenues. In addition, certain IRS tax policies such as tax normalization may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Our operations are affected by local, national and worldwide economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills which could lead to additional bad debt expense.

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

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

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

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

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

We also face the risks of possible loss of business due to significant events such as severe storm, severe temperature extremes, wildfires, widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force within our operating systems (or on a neighboring system).

The recent coronavirus outbreak in China is an example of how major catastrophic events throughout the world may disrupt our business. While we are a domestic company, the Company participates in a global supply chain, which includes materials and components that are sourced from China. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to reliably serve our customers.

Disruption due to events such as those noted above could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

SPS participates in biennial grid security and emergency response exercises (GridEx). These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

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

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

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. Our industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

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

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

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information. A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

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

Our electric utility business is 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. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Public Policy Risks

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

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

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

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

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

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states additionally have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Environmental Risks

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

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements. Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or the O&M costs incurred to comply with the requirements.

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

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

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

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

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

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

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

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

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	189
Harrington-Amarillo, TX, 3 Units	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units [(b)]	Wind	2019	460
		Total	4,804

(a) Summer 2019 net dependable capacity.

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

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2019:

Conductor Miles	
345 KV	9,566
230 KV	9,784
115 KV	14,662
Less than 115 KV	26,216

SPS had 452 electric utility transmission and distribution substations at Dec. 31, 2019.

Natural gas utility mains at Dec. 31, 2019:

Miles	
Transmission	20
Distribution	—

ITEM 3 — LEGAL PROCEEDINGS

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

See Note 10 to the financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFTEY DISCLOSURES

None.

PART II

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

SPS is a wholly owned subsidiary of Xcel Energy Inc. and there is no market for its common equity securities.

See Note 5 to the financial statements for further information.

The dividends declared during 2019 and 2018 were as follows:

(Millions of Dollars)	2019	2018
First quarter	$ 57.5	$ 33.3
Second quarter	83.4	30.7
Third quarter	114.6	40.0
Fourth quarter	78.3	45.4

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 SPS 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 and the results of operations for the current year as set forth in general instructions I(2)(a) of Form 10-K for wholly owned subsidiaries (reduced disclosure format).

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Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as, electric margin and ongoing earnings. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP. SPS' management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Electric Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Expenses incurred for electric fuel and purchased power are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses. These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items.

We use these non-GAAP financial measures to evaluate and provide details of SPS' core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of SPS. For the years ended Dec. 31, 2019 and Dec. 31, 2018, there were no adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

2019 Comparison with 2018

SPS' net income was approximately $263.1 million for 2019, compared with net income of $213.3 million for 2018. The increase was primarily due to higher electric margins attributable to purchased capacity costs, regulatory rate outcomes, demand revenue, higher AFUDC related to the Hale wind farm and lower income taxes, partially offset by increased interest and depreciation expense.

Electric Margin

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses. Electric revenues and margin for 2018 are before and after the impact of the TCJA:

(Millions of Dollars)	2019	2018
Electric revenues before TCJA impact	$ 1,825.8	$ 1,988.1
Electric fuel and purchased power before TCJA impact	(875.4)	(1,050.1)
Electric margin before TCJA impact	$ 950.4	$ 938.0
TCJA impact (offset as a reduction in income tax)	—	(48.3)
Electric margin	$ 950.4	$ 889.7

The following tables summarize the components of the changes in electric margin for the year ended Dec. 31, 2019:

(Millions of Dollars)	2019 vs. 2018
Purchase capacity costs	$ 40.7
Regulatory rate outcomes	24.7
Demand revenue	24.7
Wholesale transmission revenue	13.7
Sales growth	5.9
Non-fuel riders	4.3
Firm wholesale	(26.2)
PTC sharing	(16.0)
Estimated weather impact	(5.2)
Other (net)	(5.9)
Total increase in electric margin	$ 60.7

Non-Fuel Operating Expense and Other Items

Depreciation and Amortization — Depreciation and amortization expense increased $20.3 million, or 9.7%, for 2019 compared with the prior year. The increase was primarily due to the Hale wind farm being placed into service and increased capital investments.

AFUDC, Equity and Debt — AFUDC increased by $11.1 million, or 39.6% for 2019 compared with the prior year. The increase was primarily due to the Hale and Sagamore wind farms.

Interest Charges — Interest charges increased 14.8 million, or 17.5% for 2019 compared with the prior year. The increase was primarily due to higher debt levels to fund capital investments.

Income Taxes — Income tax expense decreased $13.3 million for 2019 compared with the prior year. The decrease was primarily driven by wind PTCs; partially offset by higher pretax income. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. The ETR was 8.9% for 2019 compared with 15.4% for 2018. The lower ETR in 2019 was primarily due to the items referenced above.

2018 Comparison with 2017

A discussion of changes in SPS' results of operations and liquidity and capital resources from the year ended Dec. 31, 2017 to Dec. 31, 2018 can be found in Part II, "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year 2018, which was filed with the SEC on Feb. 22, 2019. However, such discussion is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Regulation

FERC and State Regulation — The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, asset transactions and mergers, accounting practices and certain other activities of SPS, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of SPS' activities, including regulation of retail rates and environmental matters.

Xcel Energy, which includes SPS, 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 Commodity Futures Trading Commission jurisdictions.

Pending Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					SPS (NMPRC)
Rate Case	Electric	$51	July 2019	Pending	In July 2019, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $51 million. The rate request is based on an ROE of 10.35%, an equity ratio of 54.77%, a rate base of approximately $1.3 billion and a historic test year with rate base additions through Aug. 31, 2019. In December 2019, SPS revised its base rate increase request to approximately $47 million, based on an ROE of 10.10% and updated information. The request also included an increase of $14.6 million for accelerated depreciation including the early retirement of the Tolk Coal Plant in 2032. On Jan. 13, 2020, SPS and various parties filed an uncontested comprehensive stipulation. The stipulation includes a base rate revenue increase of $31 million, based on an ROE of 9.45% and an equity ratio of 54.77%. The stipulation also includes an acceleration of depreciation on the Tolk Coal Plant to reflect early retirement in 2037, which results in a total increase in depreciation expense of $8 million. The Signatories will not oppose the full application of depreciation rates associated with the 2032 retirement date in SPS' next base rate case. SPS anticipates final rates will go into effect in the second or third quarter of 2020.

Texas Electric Rate Case

In August 2019, SPS filed an electric rate case with the PUCT seeking an increase in retail electric base rates of approximately $141 million. The filing requests an ROE of 10.35%, a 54.65% equity ratio, a rate base of approximately $2.6 billion and is built on a 12 month period that ended June 30, 2019. In September 2019, SPS filed an update to the electric rate case and revised its requested increase to $136.5 million.

On Feb. 10, 2020, the Alliance of Xcel Municipalities (AXM), Texas Industrial Energy Consumers (TIEC), Office of Public Utility Counsel (OPUC) and the Department of Energy (DOE), filed testimony along with several other parties.

On Feb. 18, 2020, the PUCT Staff filed testimony that included certain adjustments and various ring-fencing measures.

Proposed modifications to SPS' request:

(Millions of Dollars)	Staff	AXM	OPUC	TIEC	DOE
SPS Direct Testimony	$ 136.5	$ 136.5	$ 136.5	$ 136.5	$ 136.5
Recommended base rate adjustments:					
ROE	(22.1)	(24.2)	(15.2)	(20.5)	(23.8)
Capital structure	(6.9)	(10.4)	—	(6.9)	(3.1)
Tolk/Harrington O&M disallowance	—	(6.6)	—	—	—
Distribution and Transmission Capital Disallowances (a)	(6.5)	—	—	—	—
Depreciation expense	(7.5)	(14.5)	(8.3)	(20.4)	—
Excess ADIT unprotected plant	—	—	(6.9)	—	—
Income Tax Expense Differences	(11.6)	—	—	—	—
Other, net	(6.8)	(6.1)	(0.4)	(0.6)	—
Total Adjustments	(61.4)	(61.8)	(30.8)	(48.4)	(26.9)
Total proposed revenue change	$ 75.1	$ 74.7	$ 105.7	$ 88.1	$ 109.6

Recommended Position	Staff	AXM	OPUC (b)	TIEC	DOE
ROE	9.1%	9.0%	—%	9.2%	9.0%
Equity Ratio	51.00%	50.00%	—%	51.00%	53.00%

(a) Staff recommends exclusion of approximately $134 million in transmission, distribution, and general plant in service in this rate case resulting in an approximate $7 million decrease to the revenue requirement.

(b) OPUC did not provide a recommendation for an ROE or equity ratio. For illustrative purposes an ROE of 9.5% was used.

The next steps in the procedural schedule are expected to be as follows:

- Rebuttal testimony — March 11, 2020; and
- Public hearing begins — March 30, 2020.

A PUCT decision and implementation of final rates is anticipated in the third quarter of 2020.

Texas State ROFR

In May 2019, the Governor signed into law Senate Bill 1938, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. The Texas Attorney General has made a motion to dismiss the federal court complaint. A ruling on the dismissal motion is expected in the first quarter of 2020.

See Rate Matters within Note 10 to the financial statements for further information.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivatives, Risk Management and Market Risk

SPS 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 8 to the financial statements for further information.

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

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

Commodity Price Risk — SPS is exposed to commodity price risk in its electric 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. Commodity price risk is also managed through the use of financial derivative instruments.

SPS' risk management policy allows it to manage commodity price risk per commission approved hedge plans.

Wholesale and Commodity Trading Risk — SPS conducts wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS' risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

Interest Rate Risk — SPS is subject to interest rate risk. SPS' 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.

A 100-basis-point change in the benchmark rate on SPS' variable rate debt would have no impact on annual pretax interest expense in 2019 and $0.4 million in 2018, respectively.

See Note 8 to the financial statements for further information.

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

At Dec. 31, 2019, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $1.2 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $1.2 million. At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $1.5 million, while a decrease in prices of 10% would have resulted in a decrease in credit exposure of $1.5 million.

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

Fair Value Measurements

SPS uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value. SPS' investments held in rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

Commodity Derivatives — SPS continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. Given the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2019.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2019.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

See Note 13 to the financial statements for further information.

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Management Report on Internal Controls Over Financial Reporting

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

SPS management assessed the effectiveness of SPS' internal control over financial reporting as of Dec. 31, 2019. 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, 2019, SPS' 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, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer and Director
Feb. 21, 2020	Feb. 21, 2020

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and Board of Directors of Southwestern Public Service Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Southwestern Public Service Company (the "Company") as of December 31, 2019 and 2018, the related statements of income, comprehensive income, cash flows and common stockholder's equity, for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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 21, 2020

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

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SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2019	2018	2017
Operating revenues	$ 1,825.8	$ 1,933.2	$ 1,918.0
Operating expenses			
Electric fuel and purchased power	875.4	1,043.5	1,055.3
Operating and maintenance expenses	285.3	282.7	285.4
Demand side management program expenses	16.6	17.7	15.5
Depreciation and amortization	229.9	209.6	193.9
Taxes (other than income taxes)	71.9	68.0	67.0
Total operating expenses	1,479.1	1,621.5	1,617.1
Operating income	346.7	311.7	300.9
Other income (expense), net	2.2	(3.0)	(1.8)
Allowance for funds used during construction — equity	26.8	19.1	9.3
Interest charges and financing costs			
Interest charges — includes other financing costs of $3.4, $2.9 and $2.5, respectively	99.3	84.5	86.2
Allowance for funds used during construction — debt	(12.3)	(8.9)	(5.4)
Total interest charges and financing costs	87.0	75.6	80.8
Income before income taxes	288.7	252.2	227.6
Income taxes	25.6	38.9	68.4
Net income	$ 263.1	$ 213.3	$ 159.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2019	2018	2017
Net income	$ 263.1	$ 213.3	$ 159.2
Other comprehensive income			
Defined pension and other postretirement benefits:			
Net pension and retiree medical loss arising during the period, net of tax of $(0.1), $0 and $0, respectively	(0.2)	—	—
Reclassification of loss to net income, net of tax of $0	0.2	—	0.1
Derivative instruments:			
Reclassification of loss to net income, net of tax of $0	—	0.1	—
Other comprehensive income	—	0.1	0.1
Comprehensive income	$ 263.1	$ 213.4	$ 159.3

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2019	2018	2017
Operating activities			
Net income	$ 263.1	$ 213.3	$ 159.2
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	232.2	210.0	193.9
Demand side management program amortization	—	1.7	1.7
Deferred income taxes	29.0	22.1	126.5
Allowance for equity funds used during construction	(26.8)	(19.1)	(9.3)
Provision for bad debts	5.7	4.9	5.1
Net derivative losses	—	0.1	0.1
Changes in operating assets and liabilities:			
Accounts receivable	(9.0)	(19.5)	(10.4)
Accrued unbilled revenues	(0.6)	15.3	(10.4)
Inventories	(20.5)	(16.0)	(1.9)
Prepayments and other	2.8	0.5	4.3
Accounts payable	(8.5)	(6.6)	11.8
Net regulatory assets and liabilities	13.8	38.2	38.1
Other current liabilities	5.8	11.6	3.4
Pension and other employee benefit obligations	(17.7)	(16.0)	(21.7)
Other, net	3.5	5.8	(19.9)
Net cash provided by operating activities	472.8	446.3	470.5
Investing activities			
Utility capital/construction expenditures	(844.4)	(1,020.9)	(550.6)
Investments in utility money pool arrangement	(133.0)	(285.0)	(142.0)
Receipts from utility money pool arrangement	133.0	350.0	77.0
Other	—	—	(0.5)
Net cash used in investing activities	(844.4)	(955.9)	(616.1)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(42.0)	42.0	(50.0)
Proceeds from issuance of long-term debt	292.2	295.0	442.3
Repayment of long-term debt, including reacquisition premiums	—	—	(271.6)
Borrowings under utility money pool arrangement	296.0	595.0	335.0
Repayments under utility money pool arrangement	(296.0)	(595.0)	(335.0)
Capital contributions from parent	426.3	336.8	143.7
Dividends paid to parent	(332.7)	(131.0)	(108.8)
Net cash provided by financing activities	343.8	542.8	155.6
Net change in cash, cash equivalents and restricted cash	(27.8)	33.2	10.0
Cash, cash equivalents and restricted cash at beginning of year	44.0	10.8	0.8
Cash, cash equivalents and restricted cash at end of year	$ 16.2	$ 44.0	$ 10.8
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (83.6)	$ (71.2)	$ (76.0)
Cash received (paid) for income taxes, net	11.9	(10.6)	41.5
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 94.5	$ 71.5	$ 85.1
Inventory transfer additions in property, plant and equipment	23.3	22.5	13.7
Operating lease right-of-use assets	548.3	—	—
Allowance for equity funds used during construction	26.8	19.1	9.3

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE CO.
BALANCE SHEETS
(amounts in millions, except share and per share data)

	Dec. 31 2019	Dec. 31 2018
Assets		
Current assets		
Cash and cash equivalents	$ 16.2	$ 44.0
Accounts receivable, net	92.7	90.7
Accounts receivable from affiliates	4.2	10.5
Investments in money pool arrangements	—	—
Accrued unbilled revenues	115.1	114.5
Inventories	31.0	33.9
Regulatory assets	20.0	26.0
Derivative instruments	15.0	17.8
Prepaid taxes	0.8	14.2
Prepayments and other	21.4	10.7
Total current assets	316.4	362.3
Property, plant and equipment, net	6,631.6	5,946.4
Other assets		
Regulatory assets	364.0	366.2
Derivative instruments	12.6	15.8
Operating lease right-of-use assets	522.4	—
Other	3.9	5.1
Total other assets	902.9	387.1
Total assets	$ 7,850.9	$ 6,695.8
Liabilities and Equity		
Current liabilities		
Short-term debt	$ —	$ 42.0
Accounts payable	168.1	191.8
Accounts payable to affiliates	20.4	19.9
Regulatory liabilities	118.1	85.8
Taxes accrued	40.4	41.6
Accrued interest	26.2	25.8
Dividends payable	46.3	45.2
Derivative instruments	3.7	3.6
Operating lease liabilities	26.9	—
Other	30.7	28.3
Total current liabilities	480.8	484.0
Deferred credits and other liabilities		
Deferred income taxes	671.8	619.1
Regulatory liabilities	732.3	780.9
Asset retirement obligations	77.3	32.4
Derivative instruments	12.8	16.4
Pension and employee benefit obligations	67.0	92.4
Operating lease liabilities	495.3	—
Other	9.4	7.9
Total deferred credits and other liabilities	2,065.9	1,549.1
Commitments and contingencies		
Capitalization		
Long-term debt	2,419.7	2,126.1
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Dec. 31, 2019 and 2018, respectively	—	—
Additional paid in capital	2,350.9	1,932.3
Retained earnings	535.0	605.7
Accumulated other comprehensive loss	(1.4)	(1.4)
Total common stockholder's equity	2,884.5	2,536.6
Total liabilities and equity	$ 7,850.9	$ 6,695.8

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE CO.
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
(amounts in millions, except 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, 2016	100	$ —	$ 1,446.2	$ 486.7	$ (1.3)	$ 1,931.6
Net income				159.2		159.2
Other comprehensive loss					0.1	0.1
Common dividends declared to parent				(104.6)		(104.6)
Contribution of capital by parent			144.0			144.0
Adoption of ASU No. 2018-02				0.3	(0.3)	—
Balance at Dec. 31, 2017	100	$ —	$ 1,590.2	$ 541.6	$ (1.5)	$ 2,130.3
Net income				213.3		213.3
Other comprehensive loss					0.1	0.1
Common dividends declared to parent				(149.2)		(149.2)
Contribution of capital by parent			342.1			342.1
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6
Net income				263.1		263.1
Other comprehensive income					—	—
Common dividends declared to parent				(333.8)		(333.8)
Contribution of capital by parent			418.6			418.6
Balance at Dec. 31, 2019	100	$ —	$ 2,350.9	$ 535.0	$ (1.4)	$ 2,884.5

See Notes to Financial Statements

Notes to Financial Statements

1. Summary of Significant Accounting Policies

General — SPS is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity.

SPS' financial statements are presented in accordance with GAAP. All of SPS' underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions. Certain amounts in the 2018 and 2017 financial statements or notes have been reclassified to conform to the 2019 presentation for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

SPS has evaluated events occurring after Dec. 31, 2019 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — SPS uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — SPS accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, SPS 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 SPS' results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — SPS accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. SPS defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. SPS uses 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 SPS' tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most 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 regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

SPS 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. SPS recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

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

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

See Note 7 for further information.

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

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

SPS records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was 2.9% in 2019, 2.9% in 2018 and 2.8% in 2017.

See Note 3 for further information.

AROs — SPS 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. SPS 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 10 for further information.

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

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

See Note 9 for further information.

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

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for SPS' expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 10 for further information.

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

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

SPS participates in SPP. SPS recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

See Note 6 for further information.

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

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

As of Dec. 31, 2019 and 2018, the allowance for bad debts was $5.3 million and $5.6 million, respectively.

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

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Inventories		
Materials and supplies	$ 24.7	$ 25.7
Fuel	6.3	8.2
Total inventories	$ 31.0	$ 33.9

Fair Value Measurements — SPS presents cash equivalents, interest rate derivatives and commodity derivatives at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, SPS 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 Notes 8 and 9 for further information.

Derivative Instruments — SPS uses derivative instruments in connection with its utility commodity price and interest rate activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on expected recovery of derivative instrument settlements through fuel and purchased energy cost recovery mechanisms. Interest rate hedging transactions are recorded as a component of interest expense.

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

See Note 8 for further information.

Other Utility Items

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

Alternative Revenue — Certain rate rider mechanisms (including DSM programs) qualify as alternative revenue programs. 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, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — SPS has implemented programs in its jurisdictions to assist customers in conserving energy and reducing peak demand on the electric system. These programs include commercial motor, air conditioner and lighting upgrades, as well as residential rebates for participation in air conditioner interruption and home weatherization.

The costs incurred for some DSM programs are deferred as permitted by the applicable regulatory jurisdiction. For those programs, costs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of lost margins 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. SPS recovers approved conservation program costs in base rate revenue or through a rider.

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

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

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

Segment Information — SPS has only one reportable segment. SPS is a wholly owned subsidiary of Xcel Energy Inc. and operates in the regulated electric utility industry providing wholesale and retail electric service in the states of Texas and New Mexico.

2. Accounting Pronouncements

Recently Issued

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after Dec. 15, 2019, and will be applied using a modified-retrospective approach, with a cumulative-effect adjustment to retained earnings as of Jan. 1, 2020. SPS expects the impact of adoption of the new standard to include first-time recognition of expected credit losses (i.e., bad debt expense) on unbilled revenues, with the initial allowance established at Jan. 1, 2020 charged to retained earnings. Recognition of this allowance and other impacts of adoption are expected to be immaterial to the financial statements.

Recently Adopted

Leases — In 2016, the FASB issued *Leases*, *Topic 842 (ASC Topic 842)*, which provides new accounting and disclosure guidance for leasing activities, most significantly requiring that operating leases be recognized on the balance sheet. SPS adopted the guidance on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions on whether agreements existing before the adoption date contain leases and whether existing leases are operating or finance leases; ASC Topic 842 refers to capital leases as finance leases.

Specifically for land easement contracts, SPS has elected the practical expedient provided by *ASU No. 2018-01 Leases: Land Easement Practical Expedient for Transition to Topic 842*, and as a result, only those easement contracts entered on or after Jan. 1, 2019 will be evaluated to determine if lease treatment is appropriate.

SPS also utilized the transition practical expedient offered by *ASU No. 2018-11 Leases: Targeted Improvements* to implement the standard on a prospective basis. As a result, reporting periods in the financial statements beginning Jan. 1, 2019 reflect the implementation of ASC Topic 842, while prior periods continue to be reported in accordance with *Leases, Topic 840 (ASC Topic 840)*. Other than first-time recognition of operating leases on its balance sheet, the implementation of ASC Topic 842 did not have a significant impact on SPS' financial statements. Adoption resulted in recognition of approximately $0.5 billion of operating lease ROU assets and current/noncurrent operating lease liabilities.

See Note 10 for leasing disclosures.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Property, plant and equipment		
Electric plant	$ 8,453.0	$ 7,227.7
CWIP	485.4	847.3
Total property, plant and equipment	8,938.4	8,075.0
Less accumulated depreciation	(2,306.8)	(2,128.6)
Property, plant and equipment, net	$ 6,631.6	$ 5,946.4

4. Regulatory Assets and Liabilities

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

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2019		Dec. 31, 2018	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	9	Various	$ 11.1	$ 203.5	$ 12.6	$ 222.1
Excess deferred taxes — TCJA	7	Various	1.7	52.0	—	55.9
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	34.1	—	27.9
Net AROs [(a)]	1, 10	Plant lives	—	26.9	—	25.7
Losses on reacquired debt		Term of related debt	0.8	21.0	0.8	21.9
Conservation programs [(b)]	1	One to two years	0.6	1.1	0.7	0.6
Other		Various	5.8	25.4	11.9	12.1
Total regulatory assets			$ 20.0	$ 364.0	$ 26.0	$ 366.2

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

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

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2019		Dec. 31, 2018	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 6.9	$ 534.9	$ 2.2	$ 569.8
Plant removal costs	1, 10	Plant lives	—	174.5	—	187.7
Revenue subject to refund		One to two years	14.6	1.1	11.3	8.1
Gain from asset sales		Various	—	2.4	—	2.4
Deferred electric energy costs		Less than one year	81.6	—	56.5	—
Contract valuation adjustments [(b)]	1, 8	Less than one year	11.7	—	14.7	—
Other		Various	3.3	19.4	1.1	12.9
Total regulatory liabilities [(c)]			$ 118.1	$ 732.3	$ 85.8	$ 780.9

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

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements.

(c) Revenue subject to refund of $3.9 million for 2019 and none for 2018 is included in other current liabilities.

At Dec. 31, 2019 and 2018, SPS' regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, SPS' regulatory assets included $56.5 million and $50.5 million at Dec. 31, 2019 and 2018, respectively, of past expenditures not earning a return. Amounts primarily related to formula rates, losses on reacquired debt and certain rate case expenditures.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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.

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Money pool borrowings for SPS were as follows:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2019	Year Ended Dec. 31 2019	2018	2017
Borrowing limit	$ 100	$ 100	$ 100	$ 100
Amount outstanding at period end	—	—	—	—
Average amount outstanding	1	8	29	13
Maximum amount outstanding	12	100	100	100
Weighted average interest rate, computed on a daily basis	1.63%	2.42%	1.96%	1.12%
Weighted average interest rate at end of period	N/A	N/A	N/A	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2019	Year Ended Dec. 31 2019	2018	2017
Borrowing limit	$ 500	$ 500	$ 400	$ 400
Amount outstanding at period end	—	—	42	—
Average amount outstanding	—	72	30	69
Maximum amount outstanding	—	316	144	176
Weighted average interest rate, computed on a daily basis	N/A	2.68%	2.27%	1.13%
Weighted average interest rate at end of period	N/A	N/A	2.80	NA

Letters of Credit — SPS may use letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2019 and 2018, there were $2 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, SPS 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 line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreement — In June 2019, SPS entered into an amended five-year credit agreement with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the exception of the following:

- Maturity extended from June 2021 to June 2024; and
- Borrowing limit increased from $400 million to $500 million.

The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of SPS' credit facility:

Debt-to-Total Capitalization Ratio [(a)] 2019	2018	Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
46%	46%	$50	2

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

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

The credit facility has a cross-default provision that SPS will be in default on its borrowings under the facility if SPS or any of its future significant subsidiaries whose total assets exceed 15% of SPS' total assets default on indebtedness in an aggregate principal amount exceeding $75 million.

If SPS 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. As of Dec. 31, 2019, SPS was in compliance with all financial covenants.

SPS had the following committed credit facilities available as of Dec. 31, 2019.

Credit Facility [(a)]	Drawn [(b)]	Available
$500	$2	$498

(a) This credit facility matures in June 2024.

(b) Includes letters of credit and outstanding commercial paper.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the facility outstanding at Dec. 31, 2019 and 2018.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of SPS is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for SPS as of Dec. 31 (millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	3.30%	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds [(b)]	4.40	Nov. 15, 2048	300	300
First mortgage bonds [(a)]	3.75	June 15, 2049	300	—
Unamortized discount			(7)	(4)
Unamortized debt issuance cost			(23)	(20)
Total long-term debt			$ 2,420	$ 2,126

(a) 2019 financing

(b) 2018 financing

Maturities of long-term debt:

(Millions of Dollars)	
2020	$ —
2021	—
2022	—
2023	—
2024	350

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Deferred Financing Costs — Deferred financing costs of approximately $23 million and $20 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2019 and 2018, respectively. SPS is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — SPS has the following preferred stock:

Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2019 and 2018
10,000,000	1.00	—

Dividend Restrictions — SPS dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. SPS is required to be current on particular interest payments before dividends can be paid.

SPS' state regulatory commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2019:

Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual (a)
Low	High	2019
45.0%	55.0%	54.4%

(a) Excludes short-term debt.

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization (a)
$ 535.0 million	$ 5.3 billion	N/A

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

6. Revenues

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

(Millions of Dollars)	Year Ended Dec. 31, 2019
Major product lines	
Revenue from contracts with customers:	
Residential	$ 351.9
C&I	800.3
Other	41.1
Total retail	1,193.3
Wholesale	361.0
Transmission	239.6
Other	3.3
Total revenue from contracts with customers	1,797.2
Alternative revenue and other	28.6
Total revenues	$ 1,825.8

(Millions of Dollars)	Year Ended Dec. 31, 2018
Major product lines	
Revenue from contracts with customers:	
Residential	$ 363.7
C&I	828.3
Other	44.7
Total retail	1,236.7
Wholesale	426.0
Transmission	231.1
Other	12.8
Total revenue from contracts with customers	1,906.6
Alternative revenue and other	26.6
Total revenues	$ 1,933.2

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy (which includes SPS), generally beginning in 2018, included:

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

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

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

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

- $426 million ($559 million grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- $45 million and $28 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and
- $8 million of total estimated income tax benefit related to the federal tax reform implementation and a $2 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

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

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

Tax Year(s)	Expiration
2009 - 2013	June 2020
2014 - 2016	September 2020

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2019, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of Dec. 31, 2019 no adjustments have been proposed.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2019, SPS' 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 — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 3.7	$ 3.0
Unrecognized tax benefit — Temporary tax positions	1.5	1.5
Total unrecognized tax benefit	$ 5.2	$ 4.5

Changes in unrecognized tax benefits:

(Millions of Dollars)	2019	2018	2017
Balance at Jan. 1	$ 4.5	$ 4.3	$ 28.7
Additions based on tax positions related to the current year	0.7	0.6	0.9
Reductions based on tax positions related to the current year	(0.1)	(0.1)	(0.6)
Additions for tax positions of prior years	0.2	0.1	1.3
Reductions for tax positions of prior years	(0.1)	(0.3)	(19.9)
Settlements with taxing authorities	—	(0.1)	(6.1)
Balance at Dec. 31	$ 5.2	$ 4.5	$ 4.3

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

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (4.4)	$ (3.8)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $1.4 million and $0.8 million at Dec. 31, 2019 and Dec. 31, 2018, respectively.

As the IRS Appeals and federal audit progresses and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.7 million in the next 12 months.

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

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2019	2018	2017
Receivable (payable) for interest related to unrecognized tax benefits at Jan. 1	$ 0.7	$ 0.5	$ (0.9)
Interest income related to unrecognized tax benefits	—	0.2	1.4
Receivable for interest related to unrecognized tax benefits at Dec. 31	$ 0.7	$ 0.7	$ 0.5

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2019, 2018, or 2017.

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

(Millions of Dollars)	2019	2018
Federal tax credit carryforwards	$ 29.5	$ 5.7
State NOL carryforwards	1.2	2.9

Federal carryforward periods expire between 2024 and 2039 and state carryforward periods expire between 2025 and 2036.

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

Effective income tax rate for years ended Dec. 31:

	2019	2018 [(a)]	2017 [(a)]
Federal statutory rate	21.0%	21.0%	35.0%
State income tax on pretax income, net of federal tax effect	2.2%	2.3%	2.0%
Increases (decreases) in tax from:			
Wind PTCs	(7.9)	—	—
Plant regulatory differences [(b)]	(5.0)	(4.8)	(0.9)
Amortization of excess nonplant deferred taxes	(0.9)	(1.2)	—
Other tax credits, net of NOL & tax credit allowances	(0.6)	(0.7)	(0.6)
Adjustments attributable to tax returns	(0.1)	(1.5)	(0.4)
Change in unrecognized tax benefits	0.2	0.1	(1.0)
Tax reform	—	—	(3.5)
Other, net	—	0.2	(0.5)
Effective income tax rate	8.9%	15.4%	30.1%

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

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

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

(Millions of Dollars)	2019	2018	2017
Current federal tax (benefit) expense	$ (3.9)	$ 12.3	$ (20.9)
Current state tax expense (benefit)	0.6	2.3	(12.8)
Current change in unrecognized tax expense (benefit)	—	2.3	(24.3)
Deferred federal tax expense	22.3	20.5	89.9
Deferred state tax expense	6.0	3.6	14.5
Deferred change in unrecognized tax expense (benefit)	0.7	(2.0)	22.1
Deferred ITCs	(0.1)	(0.1)	(0.1)
Total income tax expense	$ 25.6	$ 38.9	$ 68.4

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

(Millions of Dollars)	2019	2018	2017
Deferred tax expense (benefit) excluding items below	$ 52.7	$ 44.2	$ (414.2)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(23.8)	(22.0)	540.7
Tax benefit (expense) allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	0.1	(0.1)	—
Deferred tax expense	$ 29.0	$ 22.1	$ 126.5

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

(Millions of Dollars)	2019	2018 (a)
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 758.7	$ 680.6
Operating lease assets	115.8	—
Regulatory assets	49.7	49.2
Pension expense	33.1	32.3
Total deferred tax liabilities	$ 957.3	$ 762.1
Deferred tax assets:		
Regulatory liabilities	$ 111.2	$ 116.8
Operating lease liabilities	115.8	—
Tax credit carryforward	29.5	5.7
Deferred fuel costs	18.3	12.7
Other employee benefits	5.8	5.6
NOL carryforward	0.1	0.2
Other	4.8	2.0
Total deferred tax assets	285.5	143.0
Net deferred tax liability	$ 671.8	$ 619.1

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

8. 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 disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

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

Specific valuation methods include:

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

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.

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

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Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of Dec. 31, 2019, accumulated other comprehensive losses related to interest rate derivatives included $0.1 million 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 — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Gross notional amounts of commodity FTRs at Dec. 31, 2019 and 2018:

(Amounts in Millions) [(a)]	Dec. 31, 2019	Dec. 31, 2018
MWh of electricity	6.4	5.5

(a) Amounts are not reflective of net positions in the underlying commodities.

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

SPS' 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, 2019, three of the ten most significant counterparties for these activities, comprising $12.2 million or 35% of this credit exposure, had investment grade ratings from Standard & Poor's, Moody's or Fitch Ratings. Six of the ten most significant counterparties, comprising $22.1 million or 65% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $0.1 million or less than 1% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Nine of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on SPS' accumulated other comprehensive loss, included in the statements of common stockholder's equity and in the statements of comprehensive income:

(Millions of Dollars)	2019	2018	2017
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (0.7)	$ (0.8)	$ (0.7)
After-tax net realized losses on derivative transactions reclassified into earnings	—	0.1	—
Adoption of ASU. 2018-02 [(a)]	—	—	(0.1)
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (0.7)	$ (0.7)	$ (0.8)

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

Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial, $0.1 million and $0.1 million for the years ended Dec. 31, 2019, 2018 and 2017, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $6.5 million, $7.0 million and $0.5 million recognized for the years ended Dec. 31, 2019, 2018 and 2017, respectively, were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains of $6.0 million, $4.4 million and $0.8 million were recognized for the years ended Dec. 31, 2019, 2018 and 2017, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2019, 2018 and 2017.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2019 and 2018:

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 11.8	$ 11.8	$ —	$ 11.8	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	$ 14.7
Total current derivative assets	$ —	$ —	$ 11.8	$ 11.8	$ —	11.8	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	14.7
PPAs [(b)]						3.2						3.1
Current derivative instruments						$ 15.0						$ 17.8
Noncurrent derivative assets												
PPAs [(b)]						12.6						15.8
Noncurrent derivative instruments						$ 12.6						$ 15.8
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.1	$ 0.1	$ —	$ 0.1	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —
Total current derivative liabilities	$ —	$ —	$ 0.1	$ 0.1	$ —	0.1	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—
PPAs [(b)]						3.6						3.6
Current derivative instruments						$ 3.7						$ 3.6
Noncurrent derivative liabilities												
PPAs [(b)]						12.8						16.4
Noncurrent derivative instruments						$ 12.8						$ 16.4

(a) SPS nets derivative instruments and related collateral in its 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, 2019 and 2018. At both Dec. 31, 2019 and 2018, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS 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.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2019, 2018 and 2017:

	Year Ended Dec. 31		
(Millions of Dollars)	2019	2018	2017
Balance at Jan. 1	$ 14.7	$ 12.7	$ 2.0
Purchases	26.7	32.3	41.2
Settlements	(34.2)	(41.6)	(55.8)
Net transactions recorded during the period:			
Net gains recognized as regulatory assets	4.5	11.3	25.3
Balance at Dec. 31	$ 11.7	$ 14.7	$ 12.7

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2017 – 2019.

Fair Value of Long-Term Debt

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

	2019		2018	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 2,419.7	$ 2,706.1	$ 2,126.1	$ 2,139.8

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2019 and 2018, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

9. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2019 and 2018 were $39 million and $33 million, respectively, of which $2 million was attributable to SPS in both years. In 2019 and 2018, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2019 and 2018, of which immaterial amounts were attributable to SPS.

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

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

- Investment returns in 2019 were above the assumed level of 6.78%;
- Investment returns in 2018 were below the assumed level of 6.78%;
- Investment returns in 2017 were above the assumed level of 6.78%; and
- In 2020, Xcel Energy's expected investment-return assumption is 6.78%.

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

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

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

Plan Assets

For each of the fair value hierarchy levels, SPS' pension plan assets measured at fair value:

	Dec. 31, 2019 [(a)]					Dec. 31, 2018 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 18.9	$ —	$ —	$ —	$ 18.9	$ 21.6	$ —	$ —	$ —	$ 21.6
Commingled funds	202.5	—	—	144.8	347.3	128.6	—	—	132.5	261.1
Debt securities	—	98.2	0.6	—	98.8	—	98.1	—	—	98.1
Equity securities	12.1	—	—	—	12.1	14.4	—	—	—	14.4
Other	(16.8)	0.7	—	(2.8)	(18.9)	0.2	0.8	—	(4.0)	(3.0)
Total	$ 216.7	$ 98.9	$ 0.6	$ 142.0	$ 458.2	$ 164.8	$ 98.9	$ —	$ 128.5	$ 392.2

(a) See Note 8 for further information on fair value measurement inputs and methods.

For each of the fair value hierarchy levels, SPS' proportionate allocation of the total postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2019 [(a)]					Dec. 31, 2018 [(a)]				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 2.2	$ —	$ —	$ —	$ 2.2	$ 1.8	$ —	$ —	$ —	$ 1.8
Insurance contracts	—	4.9	—	—	4.9	—	4.3	—	—	4.3
Commingled funds:	6.7	—	—	7.4	14.1	12.8	—	—	3.8	16.6
Debt securities:	—	22.1	0.1	—	22.2	—	17.2	—	—	17.2
Equity securities:	—	—	—	—	—	—	—	—	—	—
Other	—	0.2	—	—	0.2	—	0.1	—	—	0.1
Total	$ 8.9	$ 27.2	$ 0.1	$ 7.4	$ 43.6	$ 14.6	$ 21.6	$ —	$ 3.8	$ 40.0

(a) See Note 8 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2019. No assets were transferred in or out of Level 3 for 2018.

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

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2019	2018	2019	2018
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 477.8	$ 515.9	$ 41.8	$ 47.0
Service cost	8.8	9.7	0.9	1.1
Interest cost	20.1	18.4	1.7	1.6
Plan amendments	—	—	—	—
Actuarial loss (gain)	44.2	(34.8)	0.4	(5.1)
Plan participants' contributions	—	—	0.6	0.6
Benefit payments [(a)]	(32.1)	(31.4)	(2.2)	(3.4)
Obligation at Dec. 31	$ 518.8	$ 477.8	$ 43.2	$ 41.8
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 392.2	$ 433.2	$ 40.0	$ 44.1
Actual return on plan assets	80.2	(17.6)	5.1	(1.3)
Employer contributions	17.9	8.0	0.1	—
Plan participants' contributions	—	—	0.6	0.6
Benefit payments	(32.1)	(31.4)	(2.2)	(3.4)
Fair value of plan assets at Dec. 31	$ 458.2	$ 392.2	$ 43.6	$ 40.0
Funded status of plans at Dec. 31	$ (60.6)	$ (85.6)	$ 0.4	$ (1.8)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent assets	—	—	0.4	—
Noncurrent liabilities	(60.6)	(85.6)	—	(1.8)
Net amounts recognized	$ (60.6)	$ (85.6)	$ 0.4	$ (1.8)
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	3.49%	4.31%	3.47%	4.32%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	Pri-2012	RP-2014	Pri-2012	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.00%	6.50%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.10%	5.30%
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	3	4

(a) Includes approximately $6.8 million in 2019 and $6.9 million in 2018, of lump-sum benefit payments used in the determination of a settlement charge.

Accumulated benefit obligation for the pension plan was $481.1 million and $445.8 million as of Dec. 31, 2019 and 2018, respectively.

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

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

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	2019	2018	2017	2019	2018	2017
Service cost	$ 8.8	$ 9.7	$ 9.8	$ 0.9	$ 1.1	$ 0.9
Interest cost	20.1	18.4	19.7	1.7	1.6	1.7
Expected return on plan assets	(28.6)	(28.3)	(27.9)	(2.0)	(2.5)	(2.4)
Amortization of prior service credit	(0.1)	(0.1)	—	(0.5)	(0.4)	(0.4)
Amortization of net loss	11.3	14.1	13.0	(0.4)	(0.4)	(0.6)
Settlement charge [(a)]	2.4	3.2	—	—	—	—
Net periodic pension cost (credit)	13.9	17.0	14.6	(0.3)	(0.6)	(0.8)
Costs not recognized due to effects of regulation	0.9	(2.2)	0.3	—	—	—
Net benefit cost (credit) recognized for financial reporting	$ 14.8	$ 14.8	$ 14.9	$ (0.3)	$ (0.6)	$ (0.8)
Significant Assumptions Used to Measure Costs:						
Discount rate	4.31%	3.63%	4.13%	4.32%	3.62%	4.13%
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.78	6.78	6.78	5.30	5.80	5.80

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2019 and 2018, as a result of lump-sum distributions during the 2019 and 2018 plan years, SPS recorded a total pension settlement charge of $2.4 million and $3.2 million in 2019 and 2018, respectively. A total of $0.6 million and $0.7 million of that amount was recorded in the income statement in 2019 and 2018, respectively.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2019	2018	2019	2018
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 209.7	$ 230.9	$ (11.9)	$ (9.6)
Prior service credit	(1.1)	(1.2)	(1.4)	(1.8)
Total	$ 208.6	$ 229.7	$ (13.3)	$ (11.4)
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	$ 11.0	$ 12.9	$ —	$ —
Noncurrent regulatory assets	197.6	216.8	—	—
Current regulatory liabilities	—	—	(0.8)	(0.9)
Noncurrent regulatory liabilities	—	—	(12.5)	(10.5)
Total	$ 208.6	$ 229.7	$ (13.3)	$ (11.4)
Measurement date	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018

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 2017 - 2020 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 2020, of which $14 million was attributable to SPS;
- $154 million in 2019, of which $18 million was attributable to SPS;
- $150 million in 2018, of which $8 million was attributable to SPS; and
- $162 million in 2017, of which $24 million was attributable to SPS.

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

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. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy's voluntary postretirement funding contributions were as follows:

- Expects to contribute approximately $10 million during 2020;
- $15 million during 2019;
- $11 million during 2018;
- $20 million during 2017; and
- Amounts attributable to SPS were immaterial.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2019	2018	2019	2018
Domestic and international equity securities	37%	35%	15%	18%
Long-duration fixed income securities	30	32	—	—
Short-to-intermediate fixed income securities	14	16	72	70
Alternative investments	17	15	9	8
Cash	2	2	4	4
Total	100%	100%	100%	100%

Plan Amendments — Xcel Energy, which includes SPS, 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 2019 and 2018, there were no plan amendments made which affected the benefit obligation.

Projected Benefit Payments

SPS' projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2020	$ 30.7	$ 2.9	$ —	$ 2.9
2021	29.4	2.9	—	2.9
2022	30.3	2.9	—	2.9
2023	30.4	2.9	—	2.9
2024	30.4	2.8	—	2.8
2025-2029	153.5	13.2	0.1	13.1

Defined Contribution Plans

Xcel Energy, which includes SPS, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for SPS was approximately $3 million in 2019, 2018 and 2017.

10. Commitments and Contingencies

Legal

SPS 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 complex judgments about future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation.

Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

Texas Fuel Reconciliation — In December 2018, SPS filed an application with the PUCT for reconciliation of fuel costs for the period Jan. 1, 2016, through June 30, 2018, to determine whether all fuel costs incurred were eligible for recovery. In December 2019, the PUCT issued an order disallowing recovery of costs for Texas customers related to two specific solar PPAs. These PPAs were previously approved by the NMPRC as reasonable, necessary and economic. SPS recorded a total disallowance of approximately $6 million in December 2019.

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

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for rehearing. Timing of a FERC response to rehearing requests is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. Timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include costs of the GridLiance High Plains, LLC. facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT.

In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On Oct. 31, 2018, the FERC issued an order accepting the proposed charges, subject to refund, as of Nov. 1, 2018, and set the case for settlement hearing procedures. Hearings are scheduled for May 2020, with the ALJs' initial decision expected in October 2020. SPS has incurred approximately $6 million in associated charges as of Dec. 31, 2019.

SPS Filing to Modify Wholesale Transmission Rates — In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to depreciation rates for transmission plant. The new formula rate would also provide a credit to customers of "excess" ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

Proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total recovered in SPP regional transmission rates. SPS proposed formula rate changes be effective Feb. 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of Feb. 1, 2019, subject to refund and settlement procedures. On Dec. 23, 2019, SPS filed a Stipulation and Agreement of Settlement. If approved by the FERC, the settlement would implement the requested depreciation and TCJA related changes, but would not modify current treatment of wholesale regulatory commission expenses.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for SPS, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. SPS may sometimes pay all or a portion of the cost to remediate sites where past activities of SPS' predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which SPS is alleged to have sent wastes to that site.

MGP, Landfill or Disposal Sites — SPS is currently remediating the site of a former facility. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Federal CWA WOTUS Rule — In 2015, the EPA and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". In 2019, the EPA repealed the 2015 rule and published a draft replacement rule. Until a final rule is issued, SPS cannot estimate potential impacts, but anticipates costs will be recoverable through regulatory mechanisms.

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

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. Texas' first regional haze plan has undergone federal review as described below.

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

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

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking, which was supplemented by an additional agency notice in November 2019. It is not known when the EPA will make a final decision on this proposal.

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

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

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

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

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AROs — AROs have been recorded for SPS' assets.

SPS' AROs were as follows:

(Millions of Dollars)	2019 Jan. 1, 2019	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2019
Electric						
Steam and other production	$ 22.0	$ —	$ (1.6)	$ 1.4	$ 29.5	$ 51.3
Wind	—	16.0	—	0.4	—	16.4
Distribution	9.1	—	—	0.4	—	9.5
Miscellaneous	1.3	—	—	—	(1.2)	0.1
Total liability	$ 32.4	$ 16.0	$ (1.6)	$ 2.2	$ 28.3	$ 77.3

(a) Amounts incurred related to the Hale wind farm placed in service in 2019.

(b) Amounts settled related to asbestos abatement projects.

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Changes in steam production AROs primarily related to the cost estimates to remediate ponds at production facilities.

(Millions of Dollars)	2018 Jan. 1, 2018	Accretion	Cash Flow Revisions (a)	Dec. 31, 2018 (b)
Electric				
Steam and other production	$ 20.3	$ 1.2	$ 0.5	$ 22.0
Distribution	7.0	0.3	1.8	9.1
Miscellaneous	1.2	0.1	—	1.3
Total liability	$ 28.5	$ 1.6	$ 2.3	$ 32.4

(a) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in electric distribution AROs were primarily related to increased labor costs.

(b) There were no ARO amounts incurred or settled in 2018.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of SPS' facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2019. Therefore, an ARO has not been recorded for these facilities.

Removal Costs — SPS records a regulatory liability for the plant removal costs that are recovered currently in rates. Removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. SPS 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, 2019 and 2018 were $174.5 million and $187.7 million, respectively.

Leases

SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under ASC Topic 842, adopted by SPS on Jan. 1, 2019, a contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent SPS' rights to use leased assets. Starting in 2019, the present value of future operating lease payments are recognized in current and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of SPS' leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the estimated incremental borrowing rate (weighted-average of 4.4%). SPS has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure. Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2019
PPAs	$ 500.3
Other	48.0
Gross operating lease ROU assets	548.3
Accumulated amortization	(25.9)
Net operating lease ROU assets	$ 522.4

Components of lease expense:

(Millions of Dollars)	2019	2018	2017
Operating leases			
PPA capacity payments	$ 48.1	$ 51.1	$ 51.4
Other operating leases (a)	4.9	7.9	6.4
Total operating lease expense (b)	$ 53.0	$ 59.0	$ 57.8

(a) Includes short-term lease expense of $1.5 million, $1.1 million and $1.2 million for 2019, 2018 and 2017, respectively.

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in O&M expense.

Commitments under operating leases as of Dec. 31, 2019:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases
2020	$ 46.2	$ 3.4	$ 49.6
2021	46.2	3.3	49.5
2022	46.2	3.4	49.6
2023	46.2	3.4	49.6
2024	46.2	3.5	49.7
Thereafter	404.5	51.3	455.8
Total minimum obligation	635.5	68.3	703.8
Interest component of obligation	(160.0)	(21.6)	(181.6)
Present value of minimum obligation	475.5	46.7	522.2
Less current portion			(26.9)
Noncurrent operating lease liabilities			$ 495.3
Weighted-average remaining lease term in years			14.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

Commitments under operating leases as of Dec. 31, 2018:

(Millions of Dollars)	PPA [a] [b] Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 46.7	$ 5.2	$ 51.9
2020	46.2	5.2	51.4
2021	46.2	5.1	51.3
2022	46.2	5.1	51.3
2023	46.2	5.1	51.3
Thereafter	450.8	56.3	507.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

PPAs and Fuel Contracts

Non-Lease PPAs — SPS has entered into PPAs with other utilities and energy suppliers with various expiration dates through 2024 for purchased power to meet system load and energy requirements and operating reserve obligations.

In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Capacity payments are contingent on the IPP meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts, were payments for capacity of $19.9 million, $57.6 million and $58.4 million in 2019, 2018 and 2017, respectively.

At Dec. 31, 2019, the estimated future payments for capacity that SPS is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity
2020	$ 12.3
2021	12.5
2022	12.7
2023	13.0
2024	5.9
Thereafter	—
Total	$ 56.4

Fuel Contracts — SPS has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal and natural gas requirements. These contracts expire between 2020 and 2033. SPS is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2019:

(Millions of Dollars)	Coal	Natural gas supply	Natural gas storage and transportation
2020	$ 96.7	$ 12.3	$ 28.9
2021	67.7	—	23.3
2022	38.8	—	17.4
2023	—	—	12.7
2024	—	—	6.7
Thereafter	—	—	26.3
Total	$ 203.2	$ 12.3	$ 115.3

VIEs

Under certain PPAs, SPS purchases power from IPPs for which SPS is required to reimburse fuel costs, or to participate in tolling arrangements under which SPS procures the natural gas required to produce the energy that it purchases. SPS has determined that certain IPPs are VIEs. SPS is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

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

SPS evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. SPS had approximately 1,197 MW of capacity under long-term PPAs at both Dec. 31, 2019 and 2018 with entities that have been determined to be VIEs. These agreements have expiration dates through 2041.

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

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

11. Other Comprehensive Income

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

	2019		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (0.7)	$ (0.7)	$ (1.4)
Other comprehensive loss before reclassifications (net of taxes of $0 and $(0.1), respectfully	—	(0.2)	(0.2)
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of net actuarial loss (net of taxes of $0)	—	0.2 (a)	0.2
Net current period other comprehensive income (loss)	—	—	—
Accumulated other comprehensive loss at Dec. 31	$ (0.7)	$ (0.7)	$ (1.4)

(a) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for further information.

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(Millions of Dollars)	2018 Gains and Losses on Cash Flow Hedges	2018 Defined Benefit Pension and Postretirement Items	2018 Total
Accumulated other comprehensive loss at Jan. 1	$ (0.8)	$ (0.7)	$ (1.5)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $0)	0.1 (a)	—	0.1
Net current period other comprehensive income	0.1	—	0.1
Accumulated other comprehensive loss at Dec. 31	$ (0.7)	$ (0.7)	$ (1.4)

(a) Included in interest charges.

12. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including SPS. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. SPS uses the service 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 with the utility subsidiaries.

See Note 5 for further information.

Significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Millions of Dollars)	2019	2018	2017
Operating expenses:			
Purchased power	$ —	$ —	$ 1.4
Other operating expenses — paid to Xcel Energy Services Inc.	192.0	195.1	196.6
Interest expense	0.2	0.6	—

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

(Millions of Dollars)	2019 Accounts Receivable	2019 Accounts Payable	2018 Accounts Receivable	2018 Accounts Payable
NSP-Minnesota	$ 4.2	$ —	$ 4.7	$ —
PSCo	—	0.4	—	0.7
Other subsidiaries of Xcel Energy Inc.	—	20.0	5.8	19.2
	$ 4.2	$ 20.4	$ 10.5	$ 19.9

13. Summarized Quarterly Financial Data (Unaudited)

(Millions of Dollars)	Quarter Ended March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019
Operating revenues	$ 454.1	$ 410.5	$ 533.1	$ 428.1
Operating income	74.5	81.9	135.4	54.9
Net income	54.1	58.8	105.1	45.1

(Millions of Dollars)	Quarter Ended March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 447.2	$ 481.3	$ 540.1	$ 464.6
Operating income (a)	57.1	87.6	111.0	56.0
Net income	33.1	58.5	81.5	40.2

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

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure. As of Dec. 31, 2019, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in SPS' internal control over financial reporting occurred during SPS' most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, SPS' internal control over financial reporting. SPS maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. SPS 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, 2019 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, SPS conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, SPS did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in SPS' Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

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

ITEM 9B — OTHER INFORMATION

None.

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PART III

Items 10, 11, 12 and 13 of Part III of Form 10-K have been omitted from this report for SPS 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 definitive Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 its 2020 Annual Meeting of Shareholders which definitive Proxy Statement is expected to be filed with the SEC on or about April 6, 2020. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

ITEM 15 — EXHIBITS, FINANCIAL STATEMENT SCHEDULES

1	Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2019.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Statements of Income — For the three years ended Dec. 31, 2019, 2018 and 2017.
	Statements of Comprehensive Income — For the three years ended Dec. 31, 2019, 2018 and 2017.
	Statements of Cash Flows — For the three years ended Dec. 31, 2019, 2018 and 2017.
	Balance Sheets — As of Dec. 31, 2019 and 2018.
	Statements of Common Stockholder's Equity — For the three years ended Dec. 31, 2019, 2018 and 2017.
2	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2019, 2018 and 2017.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Agreements and Benefit Plans Covering Executive Officers and Directors

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	001-03789	3.01
3.02*	By-Laws of SPS as Amended and Restated on Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	001-03789	3.02
4.01*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.02*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of 6% Series C and Series D Notes due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.04
4.03*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	001-03789	4.01
4.04*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.01
4.05*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.06*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.07*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02
4.08*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug. 9, 2017	001-03789	4.02

4.09*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	001-03789	4.02
4.10*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	001-03789	4.02
10.01*+	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.17
10.06*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06
10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.08
10.08*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Appendix A
10.09*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	001-03034	Appendix A
10.10*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.11*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.12*+	First Amendment to Exhibit 10.10 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.13*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.14*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.15*+	Second Amendment to Exhibit 10.10 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.16*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.02
10.17*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.18*+	Third Amendment to Exhibit 10.10 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.19*+	Fourth Amendment to Exhibit 10.11 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.20*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.21*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.22*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.34
10.23*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.35
10.24*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.36
10.25*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.04
10.26*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2019	001-03034	10.33
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.			
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document			
101.SCH	XBRL Schema			
101.CAL	XBRL Calculation			
101.DEF	XBRL Definition			
101.LAB	XBRL Label			

101.PRE	XBRL Presentation
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

SCHEDULE II

Southwestern Public Service Co. Valuation and Qualifying Accounts
Years Ended Dec. 31

	Allowance for bad debts		
(Millions of Dollars)	2019	2018	2017
Balance at Jan. 1	$ 5.6	$ 6.4	$ 6.4
Additions charged to costs and expenses	5.7	4.9	5.1
Additions charged to other accounts [(a)]	1.5	1.0	1.2
Deductions from reserves [(b)]	(7.5)	(6.7)	(6.3)
Balance at Dec. 31	$ 5.3	$ 5.6	$ 6.4

(a) Recovery of amounts previously written off.

(b) Deductions related 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.

	SOUTHWESTERN PUBLIC SERVICE COMPANY
Feb. 21, 2020	/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 T. HUDSON
Ben Fowke Chairman, Chief Executive Officer and Director (Principal Executive Officer)	David T. Hudson 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/ DAVID L. EVES	
David L. Eves Executive Vice President, Group President, Utilities and 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

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

2020 Form 10-Q
For the Quarterly Period Ended
March 31, 2020

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2020 or

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

Southwestern Public Service Company

(Exact name of registrant as specified in its charter)

New Mexico	001-3034	75-0575400
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(IRS Employer Identification No.)

790 South Buchanan Street Amarillo Texas	79101
(Address of Principal Executive Offices)	(Zip Code)

303 571-7511
(Registrant's Telephone Number, Including Area Code)

N/A
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
N/A	N/A	N/A

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

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

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

Large Accelerated Filer	☐	Accelerated Filer	☐
Non-accelerated Filer	☒	Smaller Reporting Company	☐
		Emerging growth company	☐

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

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

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

Class	May 7, 2020
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

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This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS 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.

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Definitions of Abbreviations

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

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOE	Department of Energy
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Other Terms and Abbreviations

ADIT	Accumulated deferred income tax
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
ASC	FASB Accounting Standards Codification
ATRR	Annual transmission revenue requirement
AXM	Alliance of Xcel Municipalities
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
DSM	Demand side management
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
IPP	Independent power producers
NAV	Net asset value
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open access transmission tariff
OPUC	Office of Public Utility Counsel
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
ROFR	Right of first refusal
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
TIEC	Texas Industrial Energy Consumers
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
VIE	Variable interest entity

Measurements

MW	Megawatts
MWh	Megawatt hours

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, assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Report on Form 10-Q and in other securities filings (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2019, and subsequent securities filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs, changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

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PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31	
	2020	2019
Operating revenues	$ 395.0	$ 454.1
Operating expenses		
Electric fuel and purchased power	187.8	230.9
Operating and maintenance expenses	69.6	72.4
Demand side management expenses	3.9	4.6
Depreciation and amortization	59.1	53.2
Taxes (other than income taxes)	21.3	18.5
Total operating expenses	341.7	379.6
Operating income	53.3	74.5
Other (expense) income, net	(2.0)	0.4
Allowance for funds used during construction — equity	5.9	10.3
Interest charges and financing costs		
Interest charges — includes other financing costs of $0.9 and $0.8, respectively	24.2	24.4
Allowance for funds used during construction — debt	(2.6)	(4.5)
Total interest charges and financing costs	21.6	19.9
Income before income taxes	35.6	65.3
Income tax (benefit) expense	(7.1)	11.2
Net income	$ 42.7	$ 54.1

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Three Months Ended March 31, 2020	2019
Operating activities		
Net income	$ 42.7	$ 54.1
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	59.7	53.8
Deferred income taxes	0.5	11.0
Allowance for equity funds used during construction	(5.9)	(10.3)
Net derivative losses	(1.4)	—
Changes in operating assets and liabilities:		
Accounts receivable	(2.4)	(1.3)
Accrued unbilled revenues	11.7	0.2
Inventories	(6.6)	(6.8)
Prepayments and other	(5.1)	(5.4)
Accounts payable	(1.4)	(9.3)
Net regulatory assets and liabilities	18.2	(1.2)
Other current liabilities	(14.9)	(16.7)
Pension and other employee benefit obligations	(15.0)	(15.9)
Other, net	1.1	0.3
Net cash provided by operating activities	81.2	52.5
Investing activities		
Utility capital/construction expenditures	(192.5)	(179.6)
Investments in utility money pool arrangement	(4.0)	—
Repayments from utility money pool arrangement	4.0	—
Net cash used in investing activities	(192.5)	(179.6)
Financing activities		
Proceeds from short-term borrowings, net	40.0	95.0
Borrowings under utility money pool arrangement	239.0	100.0
Repayments under utility money pool arrangement	(139.0)	(62.0)
Capital contributions from parent	31.4	5.8
Dividends paid to parent	(74.3)	(55.1)
Other, net	(0.4)	(0.1)
Net cash provided by financing activities	96.7	83.6
Net change in cash, cash equivalents and restricted cash	(14.6)	(43.5)
Cash, cash equivalents and restricted cash at beginning of period	16.2	44.0
Cash, cash equivalents and restricted cash at end of period	$ 1.6	$ 0.5
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (17.5)	$ (18.9)
Cash paid for income taxes, net	(2.1)	(4.9)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 56.5	$ 68.5
Inventory transfer additions in PPE	5.7	6.4
Operating lease right-of-use assets	—	548.3
Allowance for equity funds used during construction	5.9	10.3

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	March 31, 2020	Dec. 31, 2019
Assets		
Current assets		
Cash and cash equivalents	$ 1.6	$ 16.2
Accounts receivable, net	86.5	92.7
Accounts receivable from affiliates	13.5	4.2
Accrued unbilled revenues	103.1	115.1
Inventories	31.9	31.0
Regulatory assets	21.0	20.0
Derivative instruments	18.1	15.0
Prepaid taxes	3.5	0.8
Prepayments and other	23.6	21.4
Total current assets	302.8	316.4
Property, plant and equipment, net	6,774.8	6,631.6
Other assets		
Regulatory assets	371.8	364.0
Derivative instruments	13.3	12.6
Operating lease right-of-use assets	515.8	522.4
Other	3.3	3.9
Total other assets	904.2	902.9
Total assets	$ 7,981.8	$ 7,850.9
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 40.0	$ —
Borrowings under utility money pool arrangement	100.0	—
Accounts payable	167.6	168.1
Accounts payable to affiliates	27.2	20.4
Regulatory liabilities	139.5	118.1
Taxes accrued	20.3	40.4
Accrued interest	29.3	26.2
Dividends payable to parent	47.6	46.3
Derivative instruments	3.6	3.7
Current obligation under operating lease	27.4	26.9
Other	31.3	30.7
Total current liabilities	633.8	480.8
Deferred credits and other liabilities		
Deferred income taxes	677.7	671.8
Regulatory liabilities	726.5	732.3
Asset retirement obligations	78.2	77.3
Derivative instruments	11.9	12.8
Pension and employee benefit obligations	51.9	67.0
Operating lease liabilities	488.4	495.3
Other	9.8	9.4
Total deferred credits and other liabilities	2,044.4	2,065.9
Commitments and contingencies		
Capitalization		
Long-term debt	2,420.1	2,419.7
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at March 31, 2020 and Dec. 31, 2019, respectively	—	—
Additional paid in capital	2,382.9	2,350.9
Retained earnings	502.0	535.0
Accumulated other comprehensive loss	(1.4)	(1.4)
Total common stockholder's equity	2,883.5	2,884.5
Total liabilities and equity	$ 7,981.8	$ 7,850.9

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended March 31, 2020 and 2019						
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6
Net income				54.1		54.1
Dividends declared to parent				(57.5)		(57.5)
Balance at March 31, 2019	100	$ —	$ 1,932.3	$ 602.3	$ (1.4)	$ 2,533.2
Balance at Dec. 31, 2019	100	$ —	$ 2,350.9	$ 535.0	$ (1.4)	$ 2,884.5
Net income				42.7		42.7
Dividends declared to parent				(75.6)		(75.6)
Contributions of capital by parent			32.0			32.0
Adoption of ASC Topic 326				(0.1)		(0.1)
Balance at March 31, 2020	100	$ —	$ 2,382.9	$ 502.0	$ (1.4)	$ 2,883.5

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with U.S. GAAP, the financial position of SPS as of March 31, 2020 and Dec. 31, 2019; the results of its operations, including the components of net income and comprehensive income, and changes in stockholder's equity for the three months ended March 31, 2020 and 2019; and its cash flows for the three months ended March 31, 2020 and 2019. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2020 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2019 balance sheet information has been derived from the audited 2019 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019. These notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto, included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019, filed with the SEC on Feb. 21, 2020. Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

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

SPS implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $0.1 million (after tax) to retained earnings. Other than first-time recognition of an allowance for doubtful accounts on accrued unbilled revenues, the Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	March 31, 2020	Dec. 31, 2019
Accounts receivable, net		
Accounts receivable	$ 92.4	$ 98.0
Less allowance for bad debts	(5.9)	(5.3)
Accounts receivable, net	$ 86.5	$ 92.7

(Millions of Dollars)	March 31, 2020	Dec. 31, 2019
Inventories		
Materials and supplies	$ 26.2	$ 24.7
Fuel	5.7	6.3
Total inventories	$ 31.9	$ 31.0

(Millions of Dollars)	March 31, 2020	Dec. 31, 2019
Property, plant and equipment, net		
Electric plant	$ 8,502.1	$ 8,453.0
Construction work in progress	616.9	485.4
Total property, plant and equipment	9,119.0	8,938.4
Less accumulated depreciation	(2,344.2)	(2,306.8)
Property, plant and equipment, net	$ 6,774.8	$ 6,631.6

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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.

Money pool borrowings for SPS were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2020	Year Ended Dec. 31, 2019
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	100	—
Average amount outstanding	28	8
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	1.21%	2.42%
Weighted average interest rate at period end	1.15	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended March 31, 2020	Year Ended Dec. 31, 2019
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	40	—
Average amount outstanding	64	72
Maximum amount outstanding	146	316
Weighted average interest rate, computed on a daily basis	1.94%	2.68%
Weighted average interest rate at period end	2.20	N/A

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At both March 31, 2020 and Dec. 31, 2019, there were $2 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.

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Revolving Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, SPS 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 line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

As of March 31, 2020, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Outstanding [(b)]	Available
$ 500	$ 42	$ 458

(a) This credit facility expires in June 2024.
(b) Includes outstanding letters of credit.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one year periods. All extension requests are subject to majority bank group approval.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of March 31, 2020 and Dec. 31, 2019.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consists of the following:

	Three Months Ended	
(Millions of Dollars)	March 31, 2020	March 31, 2019
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 72.9	$ 88.1
C&I	169.1	205.8
Other	7.9	9.6
Total retail	249.9	303.5
Wholesale	73.2	84.8
Transmission	62.6	57.4
Other	0.6	1.0
Total revenue from contracts with customers	386.3	446.7
Alternative revenue and other	8.7	7.4
Total revenues	$ 395.0	$ 454.1

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2019 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

The following table reconciles the difference between the statutory rate and the ETR:

	Three Months Ended March 31,	
	2020	2019
Federal statutory rate	21.0 %	21.0%
State tax (net of federal tax effect)	2.3	2.1
Decreases in tax from:		
Wind PTCs	(35.7)	—
Plant regulatory differences [(a)]	(6.1)	(4.6)
Other tax credits, net of NOL & tax credit allowances	(0.7)	(0.6)
Other (net)	(0.7)	(0.7)
Effective income tax rate	(19.9)%	17.2%

(a) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

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

Tax Years	Expiration
2009 - 2013	September 2020
2014 - 2016	June 2021

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of March 31, 2020, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of March 31, 2020 no adjustments have been proposed.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of March 31, 2020, SPS' earliest open tax year 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 Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	March 31, 2020	Dec. 31, 2019
Unrecognized tax benefit — Permanent tax positions	$ 3.8	$ 3.7
Unrecognized tax benefit — Temporary tax positions	1.5	1.5
Total unrecognized tax benefit	$ 5.3	$ 5.2

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

(Millions of Dollars)	March 31, 2020	Dec. 31, 2019
NOL and tax credit carryforwards	$ (4.6)	$ (4.4)

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Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $1.6 million and $1.4 million at March 31, 2020 and Dec. 31, 2019, respectively.

As the IRS Appeals and federal audit progress and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.7 million in the next 12 months.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2020 or Dec. 31, 2019.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

Specific valuation methods include:

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

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.

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of March 31, 2020, accumulated other comprehensive loss related to interest rate derivatives included $0.1 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 — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

(Amounts in Millions) [(a)]	March 31, 2020	Dec. 31, 2019
MWh of electricity	8.1	6.4

(a) Amounts are not reflective of net positions in the underlying commodities.

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

SPS' 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 March 31, 2020, two of the ten most significant counterparties for these activities, comprising $11.5 million, or 32%, of this credit exposure, had investment grade ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Six of the ten most significant counterparties, comprising $23.3 million, or 65%, of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. Two of these significant counterparties, comprising $0.6 million or 2% of this credit exposure, had credit quality less than investment grade, based on external analysis. Nine of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were no and immaterial pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three months ended March 31, 2020 and 2019, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $0.1 million and $6.3 million were recognized for the three months ended March 31, 2020 and 2019, respectively, which were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains of $2.8 million and immaterial gains were recognized for the three months ended March 31, 2020 and 2019, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three months ended March 31, 2020 and 2019.

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

	March 31, 2020						Dec. 31, 2019					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 14.9	$ 14.9	$ —	$ 14.9	$ —	$ —	$ 11.8	$ 11.8	$ —	$ 11.8
Total current derivative assets	$ —	$ —	$ 14.9	$ 14.9	$ —	14.9	$ —	$ —	$ 11.8	$ 11.8	$ —	11.8
PPAs (b)						3.2						3.2
Current derivative instruments						$ 18.1						$ 15.0
Noncurrent derivative assets												
Electric commodity	$ —	$ —	$ 1.4	$ 1.4	$ —	$ 1.4	$ —	$ —	$ —	$ —	$ —	$ —
Total noncurrent derivative assets	$ —	$ —	$ 1.4	$ 1.4	$ —	1.4	$ —	$ —	$ —	$ —	$ —	—
PPAs (b)						11.9						12.6
Noncurrent derivative instruments						$ 13.3						$ 12.6

	March 31, 2020						Dec. 31, 2019					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 0.1	$ 0.1	$ —	$ 0.1
Total current derivative liabilities	$ —	$ —	$ —	$ —	$ —	—	$ —	$ —	$ 0.1	$ 0.1	$ —	0.1
PPAs (b)						3.6				.		3.6
Current derivative instruments						$ 3.6						$ 3.7
Noncurrent derivative liabilities												
PPAs (b)						11.9						12.8
Noncurrent derivative instruments						$ 11.9						$ 12.8

(a) SPS nets derivative instruments and related collateral in its 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 March 31, 2020 and Dec. 31, 2019. At both March 31, 2020 and Dec. 31, 2019, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

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Changes in Level 3 commodity derivatives for the three months ended March 31, 2020 and 2019:

	Three Months Ended March 31,	
(Millions of Dollars)	2020	2019
Balance at Jan. 1	$ 11.7	$ 14.7
Purchases	11.7	3.9
Settlements	(4.9)	(6.5)
Net transactions recorded during the period:		
Net losses recognized as regulatory assets and liabilities	(2.2)	(9.0)
Balance at March 31	$ 16.3	$ 3.1

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three months ended March 31, 2020 and 2019.

Fair Value of Long-Term Debt

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

	March 31, 2020		Dec. 31, 2019	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 2,420.1	$ 2,676.6	$ 2,419.7	$ 2,706.1

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of March 31, 2020 and Dec. 31, 2019, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended March 31			
	2020	2019	2020	2019
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2.4	$ 2.2	$ 0.2	$ 0.2
Interest cost [(a)]	4.5	5.0	0.4	0.4
Expected return on plan assets [(a)]	(7.4)	(7.2)	(0.5)	(0.5)
Amortization of prior service credit [(a)]	—	—	(0.1)	(0.1)
Amortization of net loss (gain) [(a)]	3.3	2.8	(0.1)	(0.1)
Net periodic benefit cost (credit)	2.8	2.8	(0.1)	(0.1)
Credits not recognized due to effects of regulation	0.5	0.4	—	—
Net benefit cost (credit) recognized for financial reporting	$ 3.3	$ 3.2	$ (0.1)	$ (0.1)

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

In January 2020, contributions of $150.0 million were made across four of Xcel Energy's pension plans, of which $14.4 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2020.

9. Commitments and Contingencies

The following include commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

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

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund the charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for a rehearing. In February 2020, FERC issued an order rejecting all rehearing requests and providing certain clarifications. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of FERC's orders at the D.C. Circuit. SPS has intervened in both appeals in support of FERC. The timing of an appeals decision is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. The timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC. facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes resulted in an increase in the ATRR of $9.5 million per year, with $6 million allocated to SPS' retail customers. The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone.

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In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On Oct. 31, 2018, the FERC issued an order accepting the proposed charges, subject to refund, as of Nov. 1, 2018, and set the case for settlement hearing procedures. Hearings are scheduled to begin in August 2020, and the ALJ's initial decision is expected in February 2021. In addition, the chief administrative law judge has appointed a new settlement judge who has ordered additional settlement discussions prior to the scheduled hearing date. SPS has incurred approximately $8.3 million in associated charges as of March 31, 2020.

SPS Filing to Modify Wholesale Transmission Rates — In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to the depreciation rates for transmission plant. The new formula rate would also provide a credit to customers of "excess" ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

The proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total being recovered in SPP regional transmission rates. SPS proposed that the formula rate changes be effective Feb. 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of Feb. 1, 2019, subject to refund and settlement procedures. On Dec. 23, 2019, SPS filed a Stipulation and Agreement of Settlement. If approved by the FERC, the settlement would implement the requested depreciation and TCJA related changes, but would not modify current treatment of wholesale regulatory commission expenses.

Environmental

MGP, Landfill and Disposal Sites — SPS is currently remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

VIEs

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

SPS had approximately 1,197 MW of capacity under long-term PPAs at March 31, 2020 and Dec. 31, 2019 with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Agreements have expiration dates through 2041.

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

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

Non-GAAP Financial Measures

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

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

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

Electric Margins

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

Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $42.7 million for the three months ended March 31, 2020 compared with approximately $54.1 million for the prior year. The decrease is primarily due to a 2019 NMPRC revised order eliminating a $10 million retroactive refund of tax reform benefits. SPS also recognized additional depreciation and less AFUDC, partially offset by lower income taxes.

Electric Margin

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power.

Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Three Months Ended March 31	
(Millions of Dollars)	2020	2019
Electric revenues	$ 395.0	$ 454.1
Electric fuel and purchased power	(187.8)	(230.9)
Electric margin	$ 207.2	$ 223.2

Changes in electric margin:

(Millions of Dollars)	2020 vs 2019
PTCs flowed back to customers (offset by a lower ETR)	$ (11.1)
New Mexico TCJA related regulatory settlement (2019)	(10.2)
Firm wholesale generation	(6.5)
Purchased capacity costs	6.1
Demand revenue	3.7
Wholesale transmission revenue, net	2.2
Other, net	(0.2)
Total decrease in electric margin	$ (16.0)

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Non-Fuel Operating Expense and Other Items

Depreciation and Amortization — Depreciation and amortization increased $5.9 million, or 11.1%, for the three months ended March 31, 2020 compared with the prior year. The increase was primarily due to the Hale Wind Farm in-servicing in June 2019 in addition to increased distribution, transmission, and general plant.

AFUDC, Equity and Debt — AFUDC decreased $6.3 million, for the first quarter of 2020 when compared with the same period in 2019. The decrease was primarily due to a decrease in wind construction projects, primarily the Hale Wind Farm.

Income Taxes — Income tax expense decreased $18.3 million for the three months ended March 31, 2020 compared with the same period in 2019. The decrease was primarily driven by an increase in wind PTCs and lower pretax earnings. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. ETR was (19.9)%, for the three months ended March 31, 2020 compared with 17.2% for the prior year, largely due to the items referenced above.

See Note 6 to the financial statements for further information.

Public Utility Regulation

The FERC and various state and local regulatory commissions regulate SPS. The electric rates charged to customers of SPS are approved by the FERC or the regulatory commissions in the states in which it operates.

The rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in rates for utility services through filings with governing commissions.

Changes in operating costs can affect SPS' financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2019 appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
NMPRC					
Rate Case	Electric	$51	July 2019	Pending	In July 2019, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $51 million. The rate request is based on an ROE of 10.35%, an equity ratio of 54.77%, a rate base of approximately $1.3 billion and a historic test year with rate base additions through Aug. 31, 2019. In December 2019, SPS revised its base rate increase request to approximately $47 million, based on a ROE of 10.10% and updated information. The request also included an increase of $14.6 million for accelerated depreciation including the early retirement of the Tolk coal plant in 2032. On Jan. 13, 2020, SPS and various parties filed an uncontested comprehensive stipulation. The stipulation includes a base rate revenue increase of $31 million, based on an ROE of 9.45% and an equity ratio of 54.77%. The stipulation also includes an acceleration of depreciation on the Tolk coal plant to reflect early retirement in 2037, which results in a total increase in depreciation expense of $8 million. The parties to the stipulation agreed not to oppose the full application of depreciation rates associated with the 2032 retirement date in SPS' next base rate case. A NMPRC decision is expected later in the year. SPS anticipates final rates will go into effect in the second or third quarter of 2020.

Texas 2019 Electric Rate Case — In August 2019, SPS filed an electric rate case with the PUCT seeking an increase in retail electric base rates of approximately $141 million. The filing requests an ROE of 10.35%, a 54.65% equity ratio, a rate base of approximately $2.6 billion and is built on a 12 month period that ended June 30, 2019. In September 2019, SPS filed an update to the electric rate case and revised its requested increase to approximately $137 million.

On Feb. 10, 2020, the AXM, TIEC, OPUC and DOE filed testimony along with several other parties. On Feb. 18, 2020, the PUCT Staff filed testimony that included certain adjustments and various ring-fencing measures.

Proposed modifications to SPS' request:

(Millions of Dollars)	Staff	AXM	OPUC	TIEC	DOE
SPS Direct Testimony	$ 137	$ 137	$ 137	$ 137	$ 137
Recommended base rate adjustments:					
ROE	(22)	(24)	(15)	(21)	(24)
Capital structure	(7)	(10)	—	(7)	(3)
Tolk/Harrington O&M disallowance	—	(7)	—	—	—
Distribution and Transmission Capital Disallowances [(a)]	(7)	—	—	—	—
Depreciation expense	(8)	(15)	(8)	(20)	—
Excess ADIT unprotected plant	—	—	(7)	—	—
Income Tax Expense Differences	(12)	—	—	—	—
Other, net	(6)	(6)	(1)	(1)	—
Total Adjustments	(62)	(62)	(31)	(49)	(27)
Total proposed revenue change	$ 75	$ 75	$ 106	$ 88	$ 110

Recommended Position	Staff	AXM	OPUC [(b)]	TIEC	DOE
ROE	9.1%	9.0%	—%	9.2%	9.0%
Equity Ratio	51.00%	50.00%	—%	51.00%	53.00%

(a) Staff recommends exclusion of approximately $134 million in transmission, distribution, and general plant in service in this rate case resulting in an approximate $7 million decrease to the revenue requirement.

(b) OPUC did not provide a recommendation for an ROE or equity ratio. For illustrative purposes an ROE of 9.5% was used.

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In March 2020, SPS filed an update to the electric rate case and revised its requested increase to approximately $130 million, based on a requested ROE of 10.1%, a 54.65% equity ratio, rate base of approximately $2.6 billion and historic test year ended June 30, 2019.

Revenue Request (Millions of Dollars)		
Hale Wind Farm	$	61
Capital investments		47
Depreciation rate change (including Tolk)		34
Cost of capital		8
Expiring purchased power contracts		(28)
Other, net		8
New revenue request	$	130

In May 2020, SPS and the intervening parties announced they have reached a constructive, unopposed settlement agreement in principle. We are working with intervening parties to document and file the settlement, which we expect to occur in the second quarter.

Final rates are expected to be retroactively applied as of Sept. 12, 2019. A decision from the PUCT is anticipated in the third quarter of 2020.

Texas State ROFR Litigation — In May 2019, the Governor signed into law Senate Bill 1938, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. The Texas Attorney General has made a motion to dismiss the federal court complaint. In February 2020, the federal court complaint was dismissed. In March 2020, the ruling was appealed.

Texas Fuel Refund — Fuel and purchased power costs are recoverable in Texas through a fixed fuel factor, which is part of SPS' rates. The PUCT rule requires refunding or surcharging of under and over-recovered amounts, including interest, when they exceed 4% of the utility's annual fuel costs on a rolling 12-month basis, as allowed by the PUCT, if this condition is expected to continue. Under the fuel cost recovery rules, SPS' 2019 total fuel and purchased power costs were over-collected by approximately $39 million, including interest. In February 2020, SPS filed an application with the PUCT requesting to provide a net refund of $39 million to customers to be issued beginning May 2020. In April 2020, interim rates were granted by a Texas administrative law judge. This case is pending final review and approval by the PUCT.

Environmental

Environmental Regulation

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans for greenhouse gas reductions from coal-fired power plants. The state plans, due to the EPA in July 2022, will evaluate and potentially require heat rate improvements at existing coal-fired plants. It is not yet known how these state plans will affect our existing coal plants, but they could require substantial additional investment, even in plants slated for retirement. SPS believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

As of March 31, 2020, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

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ITEM 1A — RISK FACTORS

There have been no material changes from the risk factors disclosed in the 2019 Form 10-K except as follows:

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

The global outbreak of COVID-19 is currently impacting countries, communities, supply chains and markets. COVID-19 has not had a material impact on our first quarter results; however, we did experience a substantive drop in our sales in April. The severity of the outbreak is uncertain and we cannot ultimately predict whether it will have a material impact on our liquidity, financial condition, or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic.

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2019, which is incorporated herein by reference as well as other information set forth in this report, which could have a material impact on our financial condition, results of operations and cash flows.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	001-03789	3.01
3.02*	By-Laws of SPS as Amended and Restated on Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	001-03789	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	XBRL Schema			
101.CAL	XBRL Calculation			
101.DEF	XBRL Definition			
101.LAB	XBRL Label			
101.PRE	XBRL Presentation			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)			

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SIGNATURES

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

Southwestern Public Service Company

May 7, 2020	By:	/s/ JEFFREY S. SAVAGE
		Jeffrey S. Savage
		Senior Vice President, Controller
		(Principal Accounting Officer)
		/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel
		Executive Vice President, Chief Financial Officer and Director
		(Principal Financial Officer)

2020 Form 10-Q
For the Quarterly Period Ended
June 30, 2020

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

(Mark One)

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

For the quarterly period ended June 30, 2020 or

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

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

New Mexico	**001-3034**	**75-0575400**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(IRS Employer Identification No.)

790 South Buchanan Street Amarillo Texas
(Address of Principal Executive Offices)

79101
(Zip Code)

303 571-7511
(Registrant's Telephone Number, Including Area Code)

N/A
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
N/A	N/A	N/A

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

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

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

Large Accelerated Filer ☐	Accelerated Filer ☐
Non-accelerated Filer ☒	Smaller Reporting Company ☐
	Emerging growth company ☐

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

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

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

Class	July 31, 2020
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

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This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS 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.

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Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies	
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Other Terms and Abbreviations	
ALJ	Administrative Law Judge
ASC	FASB Accounting Standards Codification
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
DSM	Demand side management
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
IPP	Independent power producers
LLC	Limited liability company
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open access transmission tariff
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
ROFR	Right of first refusal
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
VIE	Variable interest entity

Measurements	
MW	Megawatts
MWh	Megawatt hours

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, assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Report on Form 10-Q and in other securities filings (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2019, and subsequent securities filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs, changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

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PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended June 30		Six Months Ended June 30	
	2020	2019	2020	2019
Operating revenues	$ 423.4	$ 410.5	$ 818.4	$ 864.6
Operating expenses				
Electric fuel and purchased power	198.8	179.9	386.6	410.8
Operating and maintenance expenses	58.3	70.1	127.9	142.5
Demand side management expenses	3.7	3.8	7.6	8.4
Depreciation and amortization	64.0	57.8	123.1	111.0
Taxes (other than income taxes)	18.3	17.0	39.7	35.5
Total operating expenses	343.1	328.6	684.9	708.2
Operating income	80.3	81.9	133.5	156.4
Other income (expense), net	0.1	0.5	(1.9)	0.9
Allowance for funds used during construction — equity	7.8	8.7	13.8	19.0
Interest charges and financing costs				
Interest charges — includes other financing costs of $0.9, $0.8, $1.8 and $1.6, respectively	25.7	25.6	49.9	50.0
Allowance for funds used during construction — debt	(3.4)	(4.2)	(6.0)	(8.7)
Total interest charges and financing costs	22.3	21.4	43.9	41.3
Income before income taxes	65.9	69.7	101.5	135.0
Income tax (benefit) expense	(5.8)	10.9	(12.9)	22.1
Net income	$ 71.7	$ 58.8	$ 114.4	$ 112.9

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended June 30		Six Months Ended June 30	
	2020	2019	2020	2019
Net income	$ 71.7	$ 58.8	$ 114.4	$ 112.9
Other comprehensive income				
Pension and retiree medical benefits:				
Reclassification of loss to net income, net of tax of $—	0.1	—	0.1	—
Derivative instruments:				
Reclassification of loss to net income, net of tax of $—	—	0.1	—	0.1
Total other comprehensive income	0.1	0.1	0.1	0.1
Total comprehensive income	$ 71.8	$ 58.9	$ 114.5	$ 113.0

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Six Months Ended June 30	
	2020	2019
Operating activities		
Net income	$ 114.4	$ 112.9
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	124.3	112.1
Deferred income taxes	11.3	3.3
Allowance for equity funds used during construction	(13.8)	(19.0)
Provision for bad debts	3.1	2.1
Changes in operating assets and liabilities:		
Accounts receivable	(5.8)	(3.4)
Accrued unbilled revenues	(4.3)	(11.3)
Inventories	(16.2)	(9.9)
Prepayments and other	(3.9)	5.2
Accounts payable	4.2	(24.5)
Net regulatory assets and liabilities	(32.2)	37.0
Other current liabilities	(7.7)	1.1
Pension and other employee benefit obligations	(14.9)	(16.3)
Other, net	1.9	0.7
Net cash provided by operating activities	160.4	190.0
Investing activities		
Utility capital/construction expenditures	(520.4)	(364.2)
Investments in utility money pool arrangement	(4.0)	(100.0)
Repayments from utility money pool arrangement	4.0	—
Net cash used in investing activities	(520.4)	(464.2)
Financing activities		
Repayments of short-term borrowings, net	—	(42.0)
Proceeds from issuance of long-term debt, net	343.3	292.8
Borrowings under utility money pool arrangement	711.0	283.0
Repayments under utility money pool arrangement	(711.0)	(283.0)
Capital contributions from parent	436.0	378.8
Dividends paid to parent	(128.9)	(137.7)
Other, net	(0.3)	—
Net cash provided by financing activities	650.1	491.9
Net change in cash, cash equivalents and restricted cash	290.1	217.7
Cash, cash equivalents and restricted cash at beginning of period	16.2	44.0
Cash, cash equivalents and restricted cash at end of period	$ 306.3	$ 261.7
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (40.4)	$ (39.9)
Cash received for income taxes, net	4.6	—
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 108.4	$ 68.6
Inventory transfers to property, plant and equipment	13.7	12.6
Operating lease right-of-use assets	—	548.3
Allowance for equity funds used during construction	13.8	19.0

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	June 30, 2020	Dec. 31, 2019
Assets		
Current assets		
Cash and cash equivalents	$ 306.3	$ 16.2
Accounts receivable, net	90.1	92.7
Accounts receivable from affiliates	7.3	4.2
Accrued unbilled revenues	119.2	115.1
Inventories	33.5	31.0
Regulatory assets	21.9	20.0
Derivative instruments	18.8	15.0
Prepaid taxes	12.3	0.8
Prepayments and other	14.1	21.4
Total current assets	623.5	316.4
Property, plant and equipment, net	7,105.4	6,631.6
Other assets		
Regulatory assets	392.2	364.0
Derivative instruments	11.1	12.6
Operating lease right-of-use assets	503.8	522.4
Other	3.6	3.9
Total other assets	910.7	902.9
Total assets	$ 8,639.6	$ 7,850.9
Liabilities and Equity		
Current liabilities		
Accounts payable	$ 235.9	$ 168.1
Accounts payable to affiliates	16.5	20.4
Regulatory liabilities	98.9	118.1
Taxes accrued	32.8	40.4
Accrued interest	27.7	26.2
Dividends payable to parent	47.6	46.3
Derivative instruments	3.6	3.7
Current obligation under operating lease	27.5	26.9
Other	26.6	30.7
Total current liabilities	517.1	480.8
Deferred credits and other liabilities		
Deferred income taxes	695.9	671.8
Regulatory liabilities	729.0	732.3
Asset retirement obligations	79.1	77.3
Derivative instruments	11.0	12.8
Pension and employee benefit obligations	52.1	67.0
Operating lease liabilities	476.4	495.3
Other	10.5	9.4
Total deferred credits and other liabilities	2,054.0	2,065.9
Commitments and contingencies		
Capitalization		
Long-term debt	2,763.8	2,419.7
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at June 30, 2020 and Dec. 31, 2019, respectively	—	—
Additional paid in capital	2,786.9	2,350.9
Retained earnings	519.1	535.0
Accumulated other comprehensive loss	(1.3)	(1.4)
Total common stockholder’s equity	3,304.7	2,884.5
Total liabilities and equity	$ 8,639.6	$ 7,850.9

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended June 30, 2020 and 2019						
Balance at March 31, 2019	100	$ —	$ 1,932.3	$ 602.3	$ (1.4)	$ 2,533.2
Net income				58.8		58.8
Other comprehensive income					0.1	0.1
Dividends declared to parent				(83.4)		(83.4)
Contributions of capital by parent			375.0			375.0
Balance at June 30, 2019	100	$ —	$ 2,307.3	$ 577.7	$ (1.3)	$ 2,883.7
Balance at March 31, 2020	100	$ —	$ 2,382.9	$ 502.0	$ (1.4)	$ 2,883.5
Net income				71.7		71.7
Other comprehensive income					0.1	0.1
Dividends declared to parent				(54.6)		(54.6)
Contributions of capital by parent			404.0			404.0
Balance at June 30, 2020	100	$ —	$ 2,786.9	$ 519.1	$ (1.3)	$ 3,304.7

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Six Months Ended June 30, 2020 and 2019						
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6
Net income				112.9		112.9
Other comprehensive income					0.1	0.1
Dividends declared to parent				(140.9)		(140.9)
Contributions of capital by parent			375.0			375.0
Balance at June 30, 2019	100	$ —	$ 2,307.3	$ 577.7	$ (1.3)	$ 2,883.7
Balance at Dec. 31, 2019	100	$ —	$ 2,350.9	$ 535.0	$ (1.4)	$ 2,884.5
Net income				114.4		114.4
Other comprehensive income					0.1	0.1
Dividends declared to parent				(130.2)		(130.2)
Contributions of capital by parent			436.0			436.0
Adoption of ASC Topic 326				(0.1)		(0.1)
Balance at June 30, 2020	100	$ —	$ 2,786.9	$ 519.1	$ (1.3)	$ 3,304.7

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with U.S. GAAP, the financial position of SPS as of June 30, 2020 and Dec. 31, 2019; the results of its operations, including the components of net income and comprehensive income, and changes in stockholder's equity for the three and six months ended June 30, 2020 and 2019; and its cash flows for the six months ended June 30, 2020 and 2019. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2020 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2019 balance sheet information has been derived from the audited 2019 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019. These notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto, included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019, filed with the SEC on Feb. 21, 2020. Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

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

SPS implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $0.1 million (after tax) to retained earnings on Jan. 1, 2020. Other than first-time recognition of an allowance for doubtful accounts on accrued unbilled revenues, the Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	June 30, 2020	Dec. 31, 2019
Accounts receivable, net		
Accounts receivable	$ 96.6	$ 98.0
Less allowance for bad debts	(6.5)	(5.3)
Accounts receivable, net	$ 90.1	$ 92.7

(Millions of Dollars)	June 30, 2020	Dec. 31, 2019
Inventories		
Materials and supplies	$ 26.8	$ 24.7
Fuel	6.7	6.3
Total inventories	$ 33.5	$ 31.0

(Millions of Dollars)	June 30, 2020	Dec. 31, 2019
Property, plant and equipment, net		
Electric plant	$ 8,690.9	$ 8,453.0
Construction work in progress	802.4	485.4
Total property, plant and equipment	9,493.3	8,938.4
Less accumulated depreciation	(2,387.9)	(2,306.8)
Property, plant and equipment, net	$ 7,105.4	$ 6,631.6

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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.

Money pool borrowings for SPS were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2020	Year Ended Dec. 31, 2019
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	—
Average amount outstanding	62	8
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	0.83 %	2.42 %
Weighted average interest rate at period end	N/A	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended June 30, 2020	Year Ended Dec. 31, 2019
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	—	—
Average amount outstanding	53	72
Maximum amount outstanding	138	316
Weighted average interest rate, computed on a daily basis	1.09 %	2.68 %
Weighted average interest rate at period end	N/A	N/A

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At both June 30, 2020 and Dec. 31, 2019, there were $2 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.

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Revolving Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, SPS 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 line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of June 30, 2020, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [(a)]	Outstanding [(b)]	Available
$ 500	$ 2	$ 498

(a) This credit facility expires in June 2024.

(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of June 30, 2020 and Dec. 31, 2019.

Long-Term Borrowings

During the six months ended June 30, 2020, SPS issued $350 million of 3.15% first mortgage bonds due May 1, 2050.

5. Revenues

Revenue is classified by the type of goods/services rendered and market/customer type. SPS' operating revenues consists of the following:

	Three Months Ended	
(Millions of Dollars)	**June 30, 2020**	**June 30, 2019**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 84.8	$ 70.4
C&I	163.7	191.4
Other	8.7	9.9
Total retail	257.2	271.7
Wholesale	81.6	72.0
Transmission	76.0	60.0
Other	0.6	0.4
Total revenue from contracts with customers	415.4	404.1
Alternative revenue and other	8.0	6.4
Total revenues	$ 423.4	$ 410.5

	Six Months Ended	
(Millions of Dollars)	**June 30, 2020**	**June 30, 2019**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 157.7	$ 158.5
C&I	332.8	397.2
Other	16.6	19.5
Total retail	507.1	575.2
Wholesale	154.8	156.8
Transmission	138.6	117.4
Other	1.2	1.4
Total revenue from contracts with customers	801.7	850.8
Alternative revenue and other	16.7	13.8
Total revenues	$ 818.4	$ 864.6

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2019 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

The following table reconciles the difference between the statutory rate and the ETR:

	Six Months Ended June 30,	
	2020	**2019**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.3	2.1
Decreases in tax from:		
Wind PTCs	(26.7)	(0.2)
Plant regulatory differences [(a)]	(6.4)	(4.8)
Prior period adjustments	(2.0)	(0.7)
Other tax credits, net of NOL & tax credit allowances	(0.7)	(0.6)
Other (net)	(0.2)	(0.4)
Effective income tax rate	(12.7)%	16.4 %

(a) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

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

Tax Years	Expiration
2009 - 2013	September 2020
2014 - 2016	June 2021

In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. In April 2020, Xcel Energy and Appeals reached an agreement and no material adjustments were required.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of June 30, 2020, no adjustments have been proposed.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of June 30, 2020, SPS' earliest open tax year 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 Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	**June 30, 2020**	**Dec. 31, 2019**
Unrecognized tax benefit — Permanent tax positions	$ 3.6	$ 3.7
Unrecognized tax benefit — Temporary tax positions	1.5	1.5
Total unrecognized tax benefit	$ 5.1	$ 5.2

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

(Millions of Dollars)	June 30, 2020	Dec. 31, 2019
NOL and tax credit carryforwards	$ (4.5)	$ (4.4)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $1.8 million and $1.4 million at June 30, 2020 and Dec. 31, 2019, respectively.

As the IRS audit progresses and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $2.9 million in the next 12 months.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2020 and Dec. 31, 2019, respectively.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

Specific valuation methods include:

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

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.

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of June 30, 2020, accumulated other comprehensive loss related to interest rate derivatives included $0.1 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 — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

(Amounts in Millions) [(a)]	June 30, 2020	Dec. 31, 2019
MWh of electricity	11.9	6.4

(a) Amounts are not reflective of net positions in the underlying commodities.

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

SPS' 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 June 30, 2020, two of the nine most significant counterparties for these activities, comprising $14.8 million, or 36%, of this credit exposure, had investment grade ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Six of the nine most significant counterparties, comprising $26.0 million, or 64%, of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $0.1 million or 0.2% of this credit exposure, had credit quality less than investment grade, based on external analysis. Nine of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were immaterial pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three and six months ended June 30, 2020 and 2019.

Changes in the fair value of FTRs resulting in pre-tax net losses of $2.6 million and $2.5 million were recognized for the three and six months ended June 30, 2020, respectively, which were reclassified as regulatory assets and liabilities. There were $9.9 million and $4.6 million of pre-tax net gains recognized for the three and six months ended June 30, 2019, respectively, which were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains of $2.3 million and $5.1 million were recognized for the three and six months ended June 30, 2020, respectively and were recorded to electric fuel and purchased power. Settlement losses of $0.2 million were recognized for both the three and six months ended June 30, 2019 and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three and six months ended June 30, 2020 and 2019.

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

	June 30, 2020						Dec. 31, 2019					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 15.9	$ 15.9	$ (0.2)	$ 15.7	$ —	$ —	$ 11.8	$ 11.8	$ —	$ 11.8
Total current derivative assets	$ —	$ —	$ 15.9	$ 15.9	$ (0.2)	15.7	$ —	$ —	$ 11.8	$ 11.8	$ —	11.8
PPAs (b)						3.1						3.2
Current derivative instruments						$ 18.8						$ 15.0
Noncurrent derivative assets												
PPAs (b)						$ 11.1						$ 12.6
Noncurrent derivative instruments						$ 11.1						$ 12.6

	June 30, 2020						Dec. 31, 2019					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —	$ —	$ —	$ 0.1	$ 0.1	$ —	$ 0.1
Total current derivative liabilities	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—	$ —	$ —	$ 0.1	$ 0.1	$ —	0.1
PPAs (b)						3.6					.	3.6
Current derivative instruments						$ 3.6						$ 3.7
Noncurrent derivative liabilities												
PPAs (b)						$ 11.0						$ 12.8
Noncurrent derivative instruments						$ 11.0						$ 12.8

(a) SPS nets derivative instruments and related collateral in its 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 June 30, 2020 and Dec. 31, 2019. At both June 30, 2020 and Dec. 31, 2019, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

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Changes in Level 3 commodity derivatives for the three and six months ended June 30, 2020 and 2019:

	Three Months Ended June 30	
(Millions of Dollars)	2020	2019
Balance at April 1	$ 16.3	$ 3.1
Purchases	9.0	17.1
Settlements	(11.9)	(13.1)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	2.3	15.1
Balance at June 30	$ 15.7	$ 22.2

	Six Months Ended June 30	
(Millions of Dollars)	2020	2019
Balance at Jan. 1	$ 11.7	$ 14.7
Purchases	20.8	21.0
Settlements	(16.8)	(19.7)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets and liabilities	—	6.2
Balance at June 30	$ 15.7	$ 22.2

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and six months ended June 30, 2020 and 2019.

Fair Value of Long-Term Debt

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

	June 30, 2020		Dec. 31, 2019	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 2,763.8	$ 3,249.4	$ 2,419.7	$ 2,706.1

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of June 30, 2020 and Dec. 31, 2019, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30			
	2020	2019	2020	2019
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 2.4	$ 2.2	$ 0.2	$ 0.2
Interest cost [(a)]	4.5	5.0	0.4	0.4
Expected return on plan assets [(a)]	(7.4)	(7.2)	(0.5)	(0.5)
Amortization of prior service credit [(a)]	—	—	(0.1)	(0.1)
Amortization of net loss (gain) [(a)]	3.3	2.9	(0.1)	(0.1)
Net periodic benefit cost (credit)	2.8	2.9	(0.1)	(0.1)
Credits not recognized due to effects of regulation	0.5	0.4	—	—
Net benefit cost (credit) recognized for financial reporting	$ 3.3	$ 3.3	$ (0.1)	$ (0.1)

	Six Months Ended June 30			
	2020	2019	2020	2019
(Millions of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 4.8	$ 4.4	$ 0.5	$ 0.4
Interest cost [(a)]	9.0	10.1	0.7	0.9
Expected return on plan assets [(a)]	(14.7)	(14.3)	(0.9)	(1.0)
Amortization of prior service credit [(a)]	(0.1)	(0.1)	(0.2)	(0.3)
Amortization of net loss (gain) [(a)]	6.6	5.7	(0.2)	(0.2)
Net periodic benefit cost (credit)	5.6	5.8	(0.1)	(0.2)
Credits not recognized due to effects of regulation	1.0	0.8	—	—
Net benefit cost (credit) recognized for financial reporting	$ 6.6	$ 6.6	$ (0.1)	$ (0.2)

[(a)] The components of net periodic cost other than the service cost component are included in the line item "other income (expense), net" in the income statement or capitalized on the balance sheet as a regulatory asset.

In January 2020, contributions of $150.0 million were made across four of Xcel Energy's pension plans, of which $14.4 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2020.

9. Commitments and Contingencies

The following include commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

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

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In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund the charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for a rehearing. In February 2020, FERC issued an order rejecting all rehearing requests and providing certain clarifications. In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of FERC's orders at the D.C. Circuit. SPS has intervened in both appeals in support of FERC. The timing of an appeals decision is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, FERC issued an order denying the SPS complaint in its entirety, and finding SPP's calculations to be consistent with the SPP Tariff. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

In June 2020, the D.C. Circuit issued a decision in an unrelated proceeding (Allegheny Defense Project v. FERC), which held that FERC's longstanding use of tolling orders to extend FERC's deadline to act on the merits of requests for rehearing is improper. The effect on this decision on tolling orders previously issued by FERC is unclear.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes resulted in an increase in the annual transmission revenue requirement of $9.5 million per year, with $6 million allocated to SPS' retail customers. The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone.

In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On Oct. 31, 2018, the FERC issued an order accepting the proposed charges, subject to refund, as of Nov. 1, 2018, and set the case for settlement hearing procedures. Hearings are scheduled to begin in August 2020, and the ALJ's initial decision is expected in February 2021. In addition, the chief ALJ has appointed a new settlement judge who has ordered additional settlement discussions prior to the scheduled hearing date. SPS has incurred approximately $10.2 million in associated charges as of June 30, 2020.

SPS Filing to Modify Wholesale Transmission Rates — In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to the depreciation rates for transmission plant. The new formula rate would also provide a credit to customers of “excess” accumulated deferred income tax resulting from the TCJA and recover certain wholesale regulatory commission expenses.

The proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total being recovered in SPP regional transmission rates. SPS proposed that the formula rate changes be effective Feb. 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of Feb. 1, 2019, subject to refund and settlement procedures. On Dec. 23, 2019, SPS filed a Stipulation and Agreement of Settlement, which was approved by the FERC in April 2020.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites — SPS is currently remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

VIEs

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

SPS had approximately 1,197 MW of capacity under long-term PPAs at June 30, 2020 and Dec. 31, 2019 with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Agreements have expiration dates through 2041.

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

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

Non-GAAP Financial Measures

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

Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

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

Electric Margins

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

Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $114.4 million for the six months ended June 30, 2020 compared with approximately $112.9 million for the prior year. Year-to-date earnings were driven by lower O&M and income taxes, offset by lower electric margin and increased depreciation. Lower electric margins were attributable to lower sales from COVID-19, increased PTCs flowed back to customers (offset in income tax) and a 2019 NMPRC revised order eliminating a $10.2 million retroactive refund of tax reform benefits, partially offset by an increase in wholesale transmission revenue.

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power.

Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Six Months Ended June 30	
(Millions of Dollars)	**2020**	**2019**
Electric revenues	$ 818.4	$ 864.6
Electric fuel and purchased power	(386.6)	(410.8)
Electric margin	$ 431.8	$ 453.8

Changes in electric margin:

(Millions of Dollars)	**2020 vs 2019**
PTCs flowed back to customers (offset by a lower ETR)	$ (26.4)
Firm wholesale generation	(10.7)
New Mexico tax reform related regulatory settlement (2019)	(10.2)
Sales and demand [(a)]	(5.8)
Wholesale transmission revenue (net)	13.8
Purchased capacity costs	10.5
Estimated impact of weather	6.4
Regulatory rate outcomes (New Mexico)	4.1
Other (net)	(3.7)
Total decrease in electric margin	$ (22.0)

(a) Sales decline excludes weather impact.

Non-Fuel Operating Expense and Other Items

Depreciation and Amortization — Depreciation and amortization increased $12.1 million, or 10.9%, for the six months ended June 30, 2020 compared with the prior year. The increase was primarily due to the Hale Wind Farm in-servicing in June 2019, new FERC transmission rates implemented in March 2020, and normal system expansion primarily in transmission and general. These increases are offset by the Hale depreciation deferral as a result of the 2019 Texas electric rate case.

O&M Expenses — O&M expenses decreased $14.6 million, or (10.2)% for the six months ended June 30, 2020 compared with the prior year. The decrease was primarily due to deferred amounts associated with the Texas 2019 electric rate case and cost mitigation efforts to offset the negative impacts of COVID-19, offset by an increase in wind related amounts.

Income Taxes — Income tax expense decreased $35.0 million for the six months ended June 30, 2020 compared with the same period in 2019. The decrease was primarily driven by an increase in wind PTCs and lower pretax earnings. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. The ETR was (12.7)%, for the six months ended June 30, 2020 compared with 16.4% for the same period in 2019, largely due to the items referenced above.

See Note 6 to the financial statements for further information.

Public Utility Regulation

The FERC and various state and local regulatory commissions regulate SPS. The electric rates charged to customers of SPS are approved by the FERC or the regulatory commissions in the states in which it operates.

The rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in rates for utility services through filings with governing commissions.

Changes in operating costs can affect SPS' financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2019 and in Item 2 of SPS' Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2020, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

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Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
NMPRC					
Rate Case	Electric	$31	July 2019	Received	In July 2019, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $51 million. The rate request was based on an ROE of 10.35%, an equity ratio of 54.77%, a rate base of approximately $1.3 billion and a historic test year with rate base additions through Aug. 31, 2019. In December 2019, SPS revised its base rate increase request to approximately $47 million, based on a ROE of 10.10% and updated information. The request also included an increase of $14.6 million for accelerated depreciation including the early retirement of the Tolk coal plant in 2032. On Jan. 13, 2020, SPS and various parties filed an uncontested comprehensive stipulation. The stipulation includes a base rate revenue increase of $31 million, based on an ROE of 9.45% and an equity ratio of 54.77%. The stipulation also includes an acceleration of depreciation on the Tolk coal plant to reflect early retirement in 2037, which results in a total increase in depreciation expense of $8 million. The parties to the stipulation agreed not to oppose the full application of depreciation rates associated with the 2032 retirement date in SPS' next base rate case. On May 11, 2020, the Hearing Examiner issued a Certification of Stipulation recommending approval of the uncontested comprehensive stipulation without modification. On May 20, 2020, the NMPRC approved the stipulation without modification. New rates and tariffs were effective beginning May 28, 2020.
PUCT					
Rate Case	Electric	$141	August 2019	Pending	In August 2019, SPS filed an electric rate case with the PUCT seeking an increase in retail electric base rates of approximately $141 million. The filing requests an ROE of 10.35%, a 54.65% equity ratio, rate base of approximately $2.6 billion and utilizes a historic 12 month period that ended June 30, 2019. SPS' request was subsequently revised in March 2020 to approximately $130 million, based on a requested ROE of 10.1%, a 54.62% equity ratio, rate base of approximately $2.6 billion and historic test year ended June 30, 2019. On May 20, 2020, SPS, the PUCT Staff and various intervenors reached an uncontested settlement, which includes: • An electric rate increase of $88 million and a reset of the Transmission Cost Recovery Factor to zero; • ROE of 9.45% and equity ratio of 54.62% for allowance for funds used during construction purposes; • Depreciation rates: ◦ Tolk - 2037 end-of-life date; ◦ Hale - 25-year end-of-life date; ◦ All other generating units - end-of-life dates as proposed by SPS; and ◦ Transmission - 35% of the incremental change between existing depreciation rates and rates proposed by SPS. • Ring-fencing measures like those in other recent PUCT settlements, including: ◦ Credit agreements and indentures (e.g., no cross-default provisions); ◦ Financial covenants; ◦ Restrictions on pledging of assets and securing debt; ◦ Maintaining stand-alone credit facility and ratings; and ◦ Affiliate and non-affiliate limitations. Final rates are expected to be retroactively applied as of Sept. 12, 2019. A decision from the PUCT is anticipated in the third quarter of 2020.

Texas State ROFR Litigation — In May 2019, the Governor signed into law Senate Bill 1938, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. In February 2020, the federal court complaint was dismissed by the district court. In March 2020, the district court ruling was appealed to the United States Court of Appeals for the Fifth Circuit. The parties are awaiting a decision.

Texas Fuel Refund — Fuel and purchased power costs are recoverable in Texas through a fixed fuel factor, which is part of SPS' rates. The PUCT rule requires refunding or surcharging of under and over-recovered amounts, including interest, when they exceed 4% of the utility's annual fuel costs.

SPS' 2019 total fuel and purchased power costs were over-collected by approximately $39 million. As a result, SPS filed a request with the PUCT to refund the amount to customers. In April 2020, interim rates were granted by a Texas ALJ. This case is pending final review and approval by the PUCT.

New Mexico FPPCAC Continuation — In October 2019, SPS filed an application to the NMPRC to approve SPS' continued use of its FPPCAC and for reconciliation of fuel costs for the period Sept. 1, 2015, through June 30, 2019, which will determine whether all fuel costs incurred are eligible for recovery. SPS also proposed that it annually review its average New Mexico Deferred Fuel and Purchased Power balance and requests the NMPRC approve an Annual Deferred Fuel Balance True-Up. The proposed true-up is designed to maintain the Deferred Fuel and Purchased Power balance within a bandwidth of plus or minus 5% of annual New Mexico fuel and purchased power costs. A public hearing is scheduled to begin on Aug. 20, 2020.

Environmental

Environmental Regulation

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans for greenhouse gas reductions from coal-fired power plants. The state plans, due to the EPA in July 2022, will evaluate and potentially require heat rate improvements at existing coal-fired plants. It is not yet known how these state plans will affect our existing coal plants, but they could require substantial additional investment, even in plants slated for retirement. SPS believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

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ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of June 30, 2020, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

There have been no material changes from the risk factors disclosed in our Form 10-K for the year ended Dec. 31, 2019 except as follows:

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

The global outbreak of COVID-19 is currently impacting countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding COVID-19, the duration and magnitude of business restrictions, re-shut downs, if any, and the level and pace of economic recovery. While we are implementing contingency plans, there are no guarantees these plans will be sufficient to offset the impact of COVID-19.

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

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2019, which is incorporated herein by reference as well as other information set forth in this report, which could have a material impact on our financial condition, results of operations and cash flows.

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ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	001-03789	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	001-03789	3.02
4.01*	Supplemental Indenture No. 8, dated as of May 1, 2020 between SPS and U.S. Bank National Association, as Trustee, creating $350 million principal amount of 3.15% First Mortgage Bonds, Series due 2050	SPS Form 8-K dated May 18, 2020	001-03789	4.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	Inline XBRL Schema			
101.CAL	Inline XBRL Calculation			
101.DEF	Inline XBRL Definition			
101.LAB	Inline XBRL Label			
101.PRE	Inline XBRL Presentation			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)			

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SIGNATURES

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

Southwestern Public Service Company

July 31, 2020

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

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

2020 Form 10-Q
For the Quarterly Period Ended
September 30, 2020

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended Sept. 30, 2020 or

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

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

New Mexico	001-3034	75-0575400
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(IRS Employer Identification No.)

790 South Buchanan Street Amarillo Texas	79101
(Address of Principal Executive Offices)	(Zip Code)

303 571-7511
(Registrant's Telephone Number, Including Area Code)

N/A
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
N/A	N/A	N/A

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

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

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

Large Accelerated Filer ☐	Accelerated Filer ☐
Non-accelerated Filer ☒	Smaller Reporting Company ☐
	Emerging growth company ☐

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

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

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

Class	Oct. 29, 2020
Common Stock, $1.00 par value	100 shares

Southwestern Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this Form 10-Q with the reduced disclosure format specified in General Instruction H(2) to such Form 10-Q.

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This Form 10-Q is filed by Southwestern Public Service Company, a New Mexico corporation (SPS). SPS is a wholly owned subsidiary of Xcel Energy Inc. Additional information on Xcel Energy is available in various filings with the Securities and Exchange Commission. This report should be read in its entirety.

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Definitions of Abbreviations

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

NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
NMPRC	New Mexico Public Regulation Commission
PUCT	Public Utility Commission of Texas
SEC	Securities and Exchange Commission

Electric, Purchased Gas and Resource Adjustment Clauses

DSM	Demand side management
FPPCAC	Fuel and Purchased Power Cost Adjustment Clause

Other

AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
C&I	Commercial and Industrial
CEO	Chief executive officer
CFO	Chief financial officer
COVID-19	Novel coronavirus
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
IPP	Independent power producers
LLC	Limited liability company
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open access transmission tariff
PPA	Power purchase agreement
PTC	Production tax credit
ROE	Return on equity
ROFR	Right of first refusal
RTO	Regional Transmission Organization
SPP	Southwest Power Pool, Inc.
VIE	Variable interest entity

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, assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Quarterly Report on Form 10-Q and in other filings with the SEC (including SPS' Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2019, and subsequent filings), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: uncertainty around the impacts and duration of the COVID-19 pandemic; operational safety; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of SPS to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

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PART I — FINANCIAL INFORMATION
ITEM 1 — FINANCIAL STATEMENTS

SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2020	2019	2020	2019
Operating revenues	$ 615.3	$ 533.1	$ 1,433.7	$ 1,397.7
Operating expenses				
Electric fuel and purchased power	240.0	240.2	626.6	651.0
Operating and maintenance expenses	78.9	74.1	206.8	216.6
Demand side management expenses	4.6	4.5	12.2	12.9
Depreciation and amortization	100.2	61.3	223.3	172.3
Taxes (other than income taxes)	28.8	17.6	68.5	53.1
Total operating expenses	452.5	397.7	1,137.4	1,105.9
Operating income	162.8	135.4	296.3	291.8
Other (expense) income, net	(0.3)	1.5	(2.2)	2.4
Allowance for funds used during construction — equity	10.1	3.2	23.9	22.2
Interest charges and financing costs				
Interest charges — includes other financing costs of $1.0, $0.9, $2.8 and $2.5, respectively	39.1	26.0	89.0	76.0
Allowance for funds used during construction — debt	(4.4)	(1.5)	(10.4)	(10.2)
Total interest charges and financing costs	34.7	24.5	78.6	65.8
Income before income taxes	137.9	115.6	239.4	250.6
Income tax expense (benefit)	10.8	10.5	(2.1)	32.6
Net income	$ 127.1	$ 105.1	$ 241.5	$ 218.0

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in millions)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2020	2019	2020	2019
Net income	$ 127.1	$ 105.1	$ 241.5	$ 218.0
Other comprehensive income				
Pension and retiree medical benefits:				
Reclassification of loss to net income, net of tax of $—	—	—	0.1	0.1
Total other comprehensive income	—	—	0.1	0.1
Total comprehensive income	$ 127.1	$ 105.1	$ 241.6	$ 218.1

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in millions)

	Nine Months Ended Sept. 30	
	2020	2019
Operating activities		
Net income	$ 241.5	$ 218.0
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	225.2	174.0
Deferred income taxes	25.4	16.2
Allowance for equity funds used during construction	(23.9)	(22.2)
Provision for bad debts	4.7	4.0
Changes in operating assets and liabilities:		
Accounts receivable	(30.5)	(30.5)
Accrued unbilled revenues	(3.5)	(10.4)
Inventories	(24.1)	(16.3)
Prepayments and other	(14.0)	6.0
Accounts payable	(2.9)	(15.1)
Net regulatory assets and liabilities	(95.6)	17.6
Other current liabilities	14.5	14.1
Pension and other employee benefit obligations	(15.2)	(17.6)
Other, net	3.7	2.0
Net cash provided by operating activities	305.3	339.8
Investing activities		
Utility capital/construction expenditures	(845.4)	(632.8)
Investments in utility money pool arrangement	(4.0)	(133.0)
Repayments from utility money pool arrangement	4.0	133.0
Net cash used in investing activities	(845.4)	(632.8)
Financing activities		
Repayments of short-term borrowings, net	—	(42.0)
Proceeds from issuance of long-term debt, net	342.7	292.2
Borrowings under utility money pool arrangement	721.0	283.0
Repayments under utility money pool arrangement	(711.0)	(283.0)
Capital contributions from parent	435.4	400.8
Dividends paid to parent	(257.4)	(255.0)
Other, net	(0.3)	—
Net cash provided by financing activities	530.4	396.0
Net change in cash and cash equivalents	(9.7)	103.0
Cash and cash equivalents at beginning of period	16.2	44.0
Cash and cash equivalents at end of period	$ 6.5	$ 147.0
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (69.1)	$ (60.3)
Cash received (paid) for income taxes, net	4.0	(4.4)
Supplemental disclosure of non-cash investing and financing transactions:		
Accrued property, plant and equipment additions	$ 111.1	$ 67.5
Inventory transfers to property, plant and equipment	21.9	18.7
Operating lease right-of-use assets	—	548.3
Allowance for equity funds used during construction	23.9	22.2

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
BALANCE SHEETS (UNAUDITED)
(amounts in millions, except share and per share data)

	Sept. 30, 2020	Dec. 31, 2019
Assets		
Current assets		
Cash and cash equivalents	$ 6.5	$ 16.2
Accounts receivable, net	110.8	92.7
Accounts receivable from affiliates	11.1	4.2
Accrued unbilled revenues	118.3	115.1
Inventories	33.2	31.0
Regulatory assets	75.4	20.0
Derivative instruments	14.3	15.0
Prepaid taxes	17.5	0.8
Prepayments and other	19.9	21.4
Total current assets	407.0	316.4
Property, plant and equipment, net	7,368.5	6,631.6
Other assets		
Regulatory assets	362.2	364.0
Derivative instruments	10.3	12.6
Operating lease right-of-use assets	497.1	522.4
Other	3.4	3.9
Total other assets	873.0	902.9
Total assets	$ 8,648.5	$ 7,850.9
Liabilities and Equity		
Current liabilities		
Borrowings under utility money pool arrangement	$ 10.0	$ —
Accounts payable	230.6	168.1
Accounts payable to affiliates	16.7	20.4
Regulatory liabilities	77.2	118.1
Taxes accrued	50.9	40.4
Accrued interest	33.4	26.2
Dividends payable to parent	55.0	46.3
Derivative instruments	3.6	3.7
Operating lease liabilities	27.8	26.9
Other	25.2	30.7
Total current liabilities	530.4	480.8
Deferred credits and other liabilities		
Deferred income taxes	719.4	671.8
Regulatory liabilities	715.8	732.3
Asset retirement obligations	80.0	77.3
Derivative instruments	10.1	12.8
Pension and employee benefit obligations	51.9	67.0
Operating lease liabilities	469.3	495.3
Other	12.1	9.4
Total deferred credits and other liabilities	2,058.6	2,065.9
Commitments and contingencies		
Capitalization		
Long-term debt	2,763.7	2,419.7
Common stock — 200 shares authorized of $1.00 par value; 100 shares outstanding at Sept. 30, 2020 and Dec. 31, 2019, respectively	—	—
Additional paid in capital	2,786.9	2,350.9
Retained earnings	510.2	535.0
Accumulated other comprehensive loss	(1.3)	(1.4)
Total common stockholder's equity	3,295.8	2,884.5
Total liabilities and equity	$ 8,648.5	$ 7,850.9

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
STATEMENTS OF COMMON STOCKHOLDER'S EQUITY (UNAUDITED)
(amounts in millions, except share data)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Three Months Ended Sept. 30, 2020 and 2019						
Balance at June 30, 2019	100	$ —	$ 2,307.3	$ 577.7	$ (1.3)	$ 2,883.7
Net income				105.1		105.1
Dividends declared to parent				(114.6)		(114.6)
Contributions of capital by parent			18.0			18.0
Balance at Sept. 30, 2019	100	$ —	$ 2,325.3	$ 568.2	$ (1.3)	$ 2,892.2
Balance at June 30, 2020	100	$ —	$ 2,786.9	$ 519.1	$ (1.3)	$ 3,304.7
Net income				127.1		127.1
Dividends declared to parent				(136.0)		(136.0)
Balance at Sept. 30, 2020	100	$ —	$ 2,786.9	$ 510.2	$ (1.3)	$ 3,295.8

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholder's Equity
Nine Months Ended Sept. 30, 2020 and 2019						
Balance at Dec. 31, 2018	100	$ —	$ 1,932.3	$ 605.7	$ (1.4)	$ 2,536.6
Net income				218.0		218.0
Other comprehensive income					0.1	0.1
Dividends declared to parent				(255.5)		(255.5)
Contributions of capital by parent			393.0			393.0
Balance at Sept. 30, 2019	100	$ —	$ 2,325.3	$ 568.2	$ (1.3)	$ 2,892.2
Balance at Dec. 31, 2019	100	$ —	$ 2,350.9	$ 535.0	$ (1.4)	$ 2,884.5
Net income				241.5		241.5
Other comprehensive income					0.1	0.1
Dividends declared to parent				(266.2)		(266.2)
Contributions of capital by parent			436.0			436.0
Adoption of ASC Topic 326				(0.1)		(0.1)
Balance at Sept. 30, 2020	100	$ —	$ 2,786.9	$ 510.2	$ (1.3)	$ 3,295.8

See Notes to Financial Statements

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SOUTHWESTERN PUBLIC SERVICE COMPANY
Notes to Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary to present fairly, in accordance with U.S. GAAP, the financial position of SPS as of Sept. 30, 2020 and Dec. 31, 2019; the results of its operations, including the components of net income and comprehensive income, and changes in stockholder's equity for the three and nine months ended Sept. 30, 2020 and 2019; and its cash flows for the nine months ended Sept. 30, 2020 and 2019.

All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2020 up to the date of issuance of these financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2019 balance sheet information has been derived from the audited 2019 financial statements included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019.

These notes to the financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the financial statements and notes thereto, included in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019, filed with the SEC on Feb. 21, 2020. Due to the seasonality of SPS' electric sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the financial statements in the SPS Annual Report on Form 10-K for the year ended Dec. 31, 2019 appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

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

SPS implemented the guidance using a modified-retrospective approach, recognizing a cumulative effect charge of $0.1 million (after tax) to retained earnings on Jan. 1, 2020. Other than first-time recognition of an allowance for bad debts on accrued unbilled revenues, the Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on SPS' financial statements.

3. Selected Balance Sheet Data

(Millions of Dollars)	Sept. 30, 2020	Dec. 31, 2019
Accounts receivable, net		
Accounts receivable	$ 117.9	$ 98.0
Less allowance for bad debts	(7.1)	(5.3)
Accounts receivable, net	$ 110.8	$ 92.7

(Millions of Dollars)	Sept. 30, 2020	Dec. 31, 2019
Inventories		
Materials and supplies	$ 26.2	$ 24.7
Fuel	7.0	6.3
Total inventories	$ 33.2	$ 31.0

(Millions of Dollars)	Sept. 30, 2020	Dec. 31, 2019
Property, plant and equipment, net		
Electric plant	$ 8,751.8	$ 8,453.0
Construction work in progress	1,075.1	485.4
Total property, plant and equipment	9,826.9	8,938.4
Less accumulated depreciation	(2,458.4)	(2,306.8)
Property, plant and equipment, net	$ 7,368.5	$ 6,631.6

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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.

Money pool borrowings for SPS were as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2020	Year Ended Dec. 31, 2019
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	10	—
Average amount outstanding	—	8
Maximum amount outstanding	10	100
Weighted average interest rate, computed on a daily basis	0.09 %	2.42 %
Weighted average interest rate at period end	0.90	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2020	Year Ended Dec. 31, 2019
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	—	—
Average amount outstanding	—	72
Maximum amount outstanding	—	316
Weighted average interest rate, computed on a daily basis	N/A	2.68 %
Weighted average interest rate at period end	N/A	N/A

Letters of Credit — SPS uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At both Sept. 30, 2020 and Dec. 31, 2019, there were $2 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.

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Revolving Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, SPS 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 line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

SPS has the right to request an extension of the revolving credit facility termination date for two additional one-year periods. All extension requests are subject to majority bank group approval.

As of Sept. 30, 2020, SPS had the following committed revolving credit facility available (in millions of dollars):

Credit Facility [a]	Drawn [b]	Available
$ 500	$ 2	$ 498

(a) Expires in June 2024.

(b) Includes outstanding letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the credit facility outstanding as of Sept. 30, 2020 and Dec. 31, 2019.

Long-Term Borrowings

During the nine months ended Sept. 30, 2020, SPS issued $350 million of 3.15% first mortgage bonds due May 1, 2050.

5. Revenues

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

	Three Months Ended Sept. 30	
(Millions of Dollars)	**2020**	**2019**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 120.6	$ 119.3
C&I	219.5	222.4
Other	12.9	12.8
Total retail	353.0	354.5
Wholesale	109.4	106.6
Transmission	73.5	64.4
Other	1.4	0.6
Total revenue from contracts with customers	537.3	526.1
Alternative revenue and other	78.0	7.0
Total revenues	$ 615.3	$ 533.1

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2020**	**2019**
Major revenue types		
Revenue from contracts with customers:		
Residential	$ 278.3	$ 277.8
C&I	552.3	619.6
Other	29.5	32.3
Total retail	860.1	929.7
Wholesale	264.2	263.4
Transmission	212.1	181.8
Other	2.6	2.0
Total revenue from contracts with customers	1,339.0	1,376.9
Alternative revenue and other	94.7	20.8
Total revenues	$ 1,433.7	$ 1,397.7

6. Income Taxes

Note 7 to the financial statements included in SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2019 represents, in all material respects, the current status of other income tax matters except to the extent noted below, and are incorporated herein by reference.

The following table reconciles the difference between the statutory rate and the ETR:

	Nine Months Ended Sept. 30	
	2020	**2019**
Federal statutory rate	21.0 %	21.0 %
State tax (net of federal tax effect)	2.4	2.2
Decreases in tax from:		
Wind PTCs	(15.6)	(3.9)
Plant regulatory differences [a]	(6.2)	(4.7)
Prior period adjustments	(1.5)	(0.5)
Other tax credits, net NOL & tax credit allowances	(0.7)	(0.6)
Other (net)	(0.3)	(0.5)
Effective income tax rate	(0.9)%	13.0 %

(a) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

Federal Tax Loss Carryback Claims — In 2020, Xcel Energy identified certain expenses related to tax years 2009-2011 that qualify for an extended carryback claim. SPS is not expected to accrue any income tax expense related to this adjustment.

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

Tax Years	Expiration
2014 — 2016	July 2021

Additionally, the statute of limitations related to the federal tax loss carryback claim referenced above has been extended. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. In April 2020, Xcel Energy and Office of Appeals reached an agreement and no material adjustments were required.

In 2018, the IRS began an audit of tax years 2014 - 2016. In July 2020, Xcel Energy and the IRS reached an agreement and the related benefit was recognized.

State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Sept. 30, 2020, SPS' earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2011. As of Sept. 30, 2020, there are no state income tax audits in progress.

Unrecognized 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 ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

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Unrecognized tax benefits — permanent vs temporary:

(Millions of Dollars)	Sept. 30, 2020	Dec. 31, 2019
Unrecognized tax benefit — Permanent tax positions	$ 2.9	$ 3.7
Unrecognized tax benefit — Temporary tax positions	0.1	1.5
Total unrecognized tax benefit	$ 3.0	$ 5.2

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

(Millions of Dollars)	Sept. 30, 2020	Dec. 31, 2019
NOL and tax credit carryforwards	$ (2.2)	$ (4.4)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credit carryforwards were $2.1 million and $1.4 million at Sept. 30, 2020 and Dec. 31, 2019, respectively.

As the IRS and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $0.6 million in the next 12 months.

Payables for interest related to unrecognized tax benefits were not material and no amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2020 and Dec. 31, 2019, respectively.

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

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

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

Specific valuation methods include:

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

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.

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of SPS.

Derivative Instruments Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of Sept. 30, 2020, accumulated other comprehensive loss related to interest rate derivatives included $0.1 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 — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Amounts in Millions [(a)]	Sept. 30, 2020	Dec. 31, 2019
Megawatt hours of electricity	8.3	6.4

(a) Amounts are not reflective of net positions in the underlying commodities.

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

SPS' 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 Sept. 30, 2020, three of the 10 most significant counterparties for these activities, comprising $17.9 million, or 41%, of this credit exposure, had investment grade ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings. Six of the 10 most significant counterparties, comprising $25.5 million, or 59%, of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $0.1 million or 0.3% of this credit exposure, had credit quality less than investment grade, based on internal analysis. 10 of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Impact of Derivative Activities on Income and Accumulated Other Comprehensive Loss — There were no gains or losses and immaterial losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings for the three and nine months ended Sept. 30, 2020 and 2019, respectively.

Changes in the fair value of FTRs resulting in pre-tax net losses of $2.5 million and $5.0 million were recognized for the three and nine months ended Sept. 30, 2020, respectively, which were reclassified as regulatory assets and liabilities. There were immaterial and $4.7 million of pre-tax net gains recognized for the three and nine months ended Sept. 30, 2019, respectively, which were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains of $2.3 million and $3.6 million were recognized for the three and nine months ended Sept. 30, 2020, respectively and were recorded to electric fuel and purchased power. Settlement gains of $1.7 million and $1.5 million were recognized for the three and nine months ended Sept. 30, 2019, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2020 and 2019.

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

	Sept. 30, 2020						Dec. 31, 2019					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 11.2	$ 11.2	$ (0.1)	$ 11.1	$ —	$ —	$ 11.8	$ 11.8	$ —	$ 11.8
Total current derivative assets	$ —	$ —	$ 11.2	$ 11.2	$ (0.1)	11.1	$ —	$ —	$ 11.8	$ 11.8	$ —	11.8
PPAs [(b)]						3.2						3.2
Current derivative instruments						$ 14.3						$ 15.0
Noncurrent derivative assets												
PPAs [(b)]						$ 10.3						$ 12.6
Noncurrent derivative instruments						$ 10.3						$ 12.6

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(Millions of Dollars)	Sept. 30, 2020 Fair Value Level 1	Sept. 30, 2020 Fair Value Level 2	Sept. 30, 2020 Fair Value Level 3	Sept. 30, 2020 Fair Value Total	Sept. 30, 2020 Netting [(a)]	Sept. 30, 2020 Total	Dec. 31, 2019 Fair Value Level 1	Dec. 31, 2019 Fair Value Level 2	Dec. 31, 2019 Fair Value Level 3	Dec. 31, 2019 Fair Value Total	Dec. 31, 2019 Netting [(a)]	Dec. 31, 2019 Total
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.1	$ 0.1	$ (0.1)	$ —	$ —	$ —	$ 0.1	$ 0.1	$ —	$ 0.1
Total current derivative liabilities	$ —	$ —	$ 0.1	$ 0.1	$ (0.1)	—	$ —	$ —	$ 0.1	$ 0.1	$ —	0.1
PPAs [(b)]						3.6						3.6
Current derivative instruments						$ 3.6						$ 3.7
Noncurrent derivative liabilities												
PPAs [(b)]						$ 10.1						$ 12.8
Noncurrent derivative instruments						$ 10.1						$ 12.8

(a) SPS nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2020 and Dec. 31, 2019. At Sept. 30, 2020 and Dec. 31, 2019, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS 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.

Changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2020 and 2019:

(Millions of Dollars)	Three Months Ended Sept. 30 2020	Three Months Ended Sept. 30 2019
Balance at July 1	$ 15.7	$ 22.2
Purchases	0.3	4.4
Settlements	(1.3)	(5.2)
Net transactions recorded during the period:		
Net losses recognized as regulatory assets and liabilities	(3.6)	(4.3)
Balance at Sept. 30	$ 11.1	$ 17.1

(Millions of Dollars)	Nine Months Ended Sept. 30 2020	Nine Months Ended Sept. 30 2019
Balance at Jan. 1	$ 11.7	$ 14.7
Purchases	21.1	25.5
Settlements	(18.2)	(24.9)
Net transactions recorded during the period:		
Net (losses) gains recognized as regulatory assets and liabilities	(3.5)	1.8
Balance at Sept. 30	$ 11.1	$ 17.1

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2020 and 2019.

Fair Value of Long-Term Debt

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

(Millions of Dollars)	Sept. 30, 2020 Carrying Amount	Sept. 30, 2020 Fair Value	Dec. 31, 2019 Carrying Amount	Dec. 31, 2019 Fair Value
Long-term debt	$ 2,763.7	$ 3,314.4	$ 2,419.7	$ 2,706.1

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Sept. 30, 2020 and Dec. 31, 2019 and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

(Millions of Dollars)	Three Months Ended Sept. 30 Pension Benefits 2020	Pension Benefits 2019	Postretirement Health Care Benefits 2020	Postretirement Health Care Benefits 2019
Service cost	$ 2.4	$ 2.2	$ 0.3	$ 0.2
Interest cost [(a)]	4.5	5.0	0.3	0.4
Expected return on plan assets [(a)]	(7.4)	(7.1)	(0.5)	(0.5)
Amortization of prior service credit [(a)]	—	—	(0.1)	(0.1)
Amortization of net loss (gain) [(a)]	3.3	2.8	(0.1)	(0.1)
Net periodic benefit cost (credit)	2.8	2.9	(0.1)	(0.1)
Effects of regulation	0.5	0.5	—	—
Net benefit cost (credit) recognized for financial reporting	$ 3.3	$ 3.4	$ (0.1)	$ (0.1)

(Millions of Dollars)	Nine Months Ended Sept. 30 Pension Benefits 2020	Pension Benefits 2019	Postretirement Health Care Benefits 2020	Postretirement Health Care Benefits 2019
Service cost	$ 7.2	$ 6.6	$ 0.7	$ 0.7
Interest cost [(a)]	13.4	15.1	1.1	1.3
Expected return on plan assets [(a)]	(22.0)	(21.5)	(1.4)	(1.5)
Amortization of prior service credit [(a)]	(0.1)	(0.1)	(0.3)	(0.4)
Amortization of net loss (gain) [(a)]	9.9	8.5	(0.3)	(0.3)
Net periodic benefit cost (credit)	8.4	8.6	(0.2)	(0.2)
Effects of regulation	1.5	1.3	—	—
Net benefit cost (credit) recognized for financial reporting	$ 9.9	$ 9.9	$ (0.2)	$ (0.2)

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

In January 2020, contributions of $150.0 million were made across four of Xcel Energy's pension plans, of which $14.4 million was attributable to SPS. Xcel Energy does not expect additional pension contributions during 2020.

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9. Commitments and Contingencies

The following include commitments, contingencies and unresolved contingencies that are material to SPS' financial position.

Legal

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters and Other

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

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover these previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund the charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015.

In March 2020, SPP and Oklahoma Gas & Electric separately filed petitions for review of FERC's orders at the D.C. Circuit. SPS has intervened in both appeals in support of FERC. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate related complaint against SPP asserting that SPP has assessed upgrade charges to SPS in violation of the SPP OATT. In March 2018, the FERC issued an order denying the SPS complaint in its entirety and found SPP's calculations to be consistent with the SPP Tariff. SPS filed a request for rehearing in April 2018. The FERC issued a tolling order granting a rehearing for further consideration in May 2018. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include the costs of the GridLiance High Plains, LLC facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT. SPP's proposed tariff changes resulted in an increase in the annual transmission revenue requirement of $9.5 million per year, with $6 million allocated to SPS' retail customers. The remaining $3.5 million would be paid by other wholesale loads in the SPS rate zone.On March 16, 2020, GridLiance also filed additional rate increases for 2020 which would raise their annual revenue requirement to $13.6 million, with approximately $8.7 million allocated to SPS' retail customers. The hearing portion of this proceeding was concluded on Sept. 11, 2020. The initial post-hearing brief was filed on Oct. 27, 2020 and the administrative law judge's decision on this case is expected on Feb. 3, 2021. The FERC will then rule on the judge's decision and either sustain it, overturn it, or order further proceedings. SPS has incurred approximately $12.6 million in associated charges as of Sept. 30, 2020.

Contract Termination — SPS and Lubbock Power & Light are parties to a 25-year, 170 MW partial requirements contract. Lubbock Power & Light has initiated discussions with SPS concerning the interpretation of contractual terms related to early termination and default. If the parties are unable to reach resolution, the contract calls for the matter to proceed to arbitration.

Environmental

Manufactured Gas Plant, Landfill and Disposal Sites — SPS is currently remediating a former disposal site. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

VIEs

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

SPS had approximately 1,197 megawatts of capacity under long-term PPAs at Sept. 30, 2020 and Dec. 31, 2019 with entities that have been determined to be VIEs. SPS concluded that these entities are not required to be consolidated in its financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. The PPAs have expiration dates through 2041.

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

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

Non-GAAP Financial Measures

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

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Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

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

Electric Margin

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

Management believes electric margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, O&M expenses, DSM expenses, depreciation and amortization and taxes (other than income taxes).

Results of Operations

SPS' net income was approximately $241.5 million for the nine months ended Sept. 30, 2020 compared with approximately $218.0 million for the prior year. Year-to-date results reflect higher electric margin (regulatory outcomes offset lower sales due to COVID-19) and lower O&M expenses, partially offset by increased depreciation, interest expense and taxes (other than income taxes).

Electric Margin

Electric revenues and fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Changes in fuel or purchased power costs can impact earnings as the fuel and purchased power cost recovery mechanisms of the Texas and New Mexico jurisdictions may not allow for complete recovery of all expenses.

Electric revenues and margin:

	Nine Months Ended Sept. 30	
(Millions of Dollars)	**2020**	**2019**
Electric revenues	$ 1,433.7	$ 1,397.7
Electric fuel and purchased power	(626.6)	(651.0)
Electric margin	$ 807.1	$ 746.7

Changes in electric margin:

(Millions of Dollars)	**2020 vs. 2019**
Regulatory rate outcomes (Texas and New Mexico) [a]	$ 87.8
Wholesale transmission revenue (net)	19.7
Purchased capacity costs	9.3
Estimated impact of weather	7.5
PTCs flowed back to customers (offset by lower ETR)	(35.1)
Firm wholesale generation	(10.5)
New Mexico tax reform related regulatory settlement (2019)	(10.2)
Sales and demand [b]	(8.0)
Other (net)	(0.1)
Total increase in electric margin	$ 60.4

(a) Includes approximately $70 million of revenue and margin due to the Texas rate case outcome, which is largely offset by recognition of previously deferred costs see Public Utility Regulation below for more information.

(b) Sales decline excludes weather impact.

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses decreased $9.8 million, or 4.5% year-to-date. The decrease was due to plant outages in 2019, as well as management actions to reduce costs to offset the impact of lower sales from COVID-19, including allocation of workforce, material and supply management and timing of maintenance activities. The decrease was partially offset by an increase in wind related O&M expenses from our renewable expansion and recognition of previously deferred amounts related with the Texas Electric Rate Case.

Depreciation and Amortization — Depreciation and amortization increased $51 million, or 29.6%, year-to-date. The increase was primarily due to the June 2019 Hale Wind Farm in-servicing, new FERC transmission rates implemented in March 2020 and normal system expansion primarily in transmission and general. In addition, new depreciation rates were implemented in both New Mexico and Texas as part of regulatory outcomes in 2020.

Income Taxes — Income tax expense decreased $34.7 million year-to-date. The decrease was primarily driven by an increase in wind PTCs, an increase in plant regulatory differences and lower pretax earnings. Wind PTCs are largely credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. The ETR was (0.9)% for the nine months ended Sept. 30, 2020 compared with 13.0% for 2019, largely due to the items referenced above.

See Note 6 to the financial statements for further information.

Public Utility Regulation

The FERC and various state and local regulatory commissions regulate SPS. The electric rates charged to customers of SPS are approved by the FERC or the regulatory commissions in the states in which it operates.

The rates are designed to recover plant investment, operating costs and an allowed return on investment. SPS requests changes in rates for utility services through filings with governing commissions.

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Changes in operating costs can affect SPS' financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact SPS' results of operations.

Except to the extent noted below, the circumstances set forth in Public Utility Regulation included in Item 7 of SPS' Annual Report on Form 10-K for the year ended Dec. 31, 2019 and in Item 2 of SPS' Quarterly Reports on Form 10-Q for the quarterly period ended March 31, 2020 and Form 10-Q for the quarterly period ended June 30, 2020, appropriately represent, in all material respects, the current status of public utility regulation and are incorporated herein by reference.

Pending and Recently Concluded Regulatory Proceedings

Proceeding	Amount (in millions)	Filing Date	Approval
2019 Texas Electric Rate Case	$88	August 2019	Received
2020 New Mexico Electric Rate Case	TBD	January 2021	Pending Filing
2020 Texas Electric Rate Case	TBD	February 2021	Pending Filing

Additional Information:

2019 Texas Electric Rate Case — In August 2020, the PUCT approved a settlement between SPS and intervening parties, which reflects the following terms, retroactive to Sept. 12, 2019:

- An electric rate increase of $88 million;
- ROE of 9.45% and equity ratio of 54.62% for AFUDC purposes;
- Acceleration of the depreciation life of the Tolk coal plant; and
- Ring-fencing measures, similar to other Texas utilities.

SPS expects to submit a filing in the fourth quarter of 2020 to surcharge the final under-recovered amount, which is estimated to be approximately $70 million, offset by the recognition of previously deferred costs. The impact of the retroactive amounts (related to period prior to Sept. 1, 2020) is as follows:

(Millions of Dollars)	Nine Months Ended Sept. 30, 2020
Revenue surcharge accrual	$ 70
Depreciation and amortization	(37)
O&M expense	(15)
Interest expense	(11)
Taxes other than income taxes	(7)

2020 Electric Rate Cases — In the first quarter of 2021, SPS intends to file electric rate cases for both the Texas and New Mexico jurisdictions due to the settlement reached for the Hale and Sagamore wind farms.

Texas State ROFR Litigation — In May 2019, the Governor signed into law a ROFR Bill, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. In February 2020, the federal court complaint was dismissed by the district court. In March 2020, the district court ruling was appealed to the United States Court of Appeals for the Fifth Circuit. The parties are awaiting a decision.

Texas Fuel Refund — Fuel and purchased power costs are recoverable in Texas through a fixed fuel factor, which is part of SPS' rates. The PUCT rule requires refunding or surcharging of under and over-recovered amounts, including interest, when they exceed 4% of the utility's annual fuel costs.

In August 2020, the PUCT approved SPS' request to refund approximately $39 million to customers for over-collected fuel and purchased power costs.

New Mexico FPPCAC Continuation — In October 2019, SPS filed an application to the NMPRC to approve SPS' continued use of its FPPCAC and for reconciliation of fuel costs for the period Sept. 1, 2015, through June 30, 2019, which will determine whether all fuel costs incurred are eligible for recovery. SPS also proposed that it annually review its average New Mexico Deferred Fuel and Purchased Power balance and requests the NMPRC approve an Annual Deferred Fuel Balance True-Up. The proposed true-up is designed to maintain the Deferred Fuel and Purchased Power balance within a bandwidth of plus or minus 5% of annual New Mexico fuel and purchased power costs. A decision is pending.

Environmental

Environmental Regulation

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans for greenhouse gas reductions from coal-fired power plants. The state plans, due to the EPA in July 2022, will evaluate and potentially require heat rate improvements at existing coal-fired plants. It is not yet known how these state plans will affect our existing coal plants, but they could require substantial additional investment, even in plants slated for retirement. SPS believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

On Oct. 21, 2020, the Texas Commission on Environmental Quality approved the Harrington Station Power Plant agreement, which ensures SPS will cease coal-fired operations and convert the plant to natural gas by Jan. 1, 2025. This conversion is necessary to attain Federal Clean Air Act standards for emissions of sulfur dioxide.

ITEM 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

SPS maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms.

In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure.

As of Sept. 30, 2020, based on an evaluation carried out under the supervision and with the participation of SPS' management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that SPS' disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

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PART II — OTHER INFORMATION

ITEM 1 — LEGAL PROCEEDINGS

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

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 9 to the financial statements and Part I Item 2 for further information.

ITEM 1A — RISK FACTORS

There have been no material changes from the risk factors disclosed in our Form 10-K for the year ended Dec. 31, 2019 except as follows:

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

The global outbreak of COVID-19 is currently impacting countries, communities, supply chains and markets. A high degree of uncertainty continues to exist regarding COVID-19, the duration and magnitude of business restrictions, re-shut downs, if any, and the level and pace of economic recovery. While we are implementing contingency plans, there are no guarantees these plans will be sufficient to offset the impact of COVID-19.

Although we do not expect the impact of COVID-19 to be material to the 2020 results, we cannot ultimately predict whether it will have a material impact on our future liquidity, financial condition, or results of operations. Nor can we predict the impact of the virus on the health of our employees, our supply chain or our ability to recover higher costs associated with managing through the pandemic.

SPS' risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2019, which is incorporated herein by reference as well as other information set forth in this report, which could have a material impact on our financial condition, results of operations and cash flows.

ITEM 6 — EXHIBITS

* Indicates incorporation by reference

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation, dated Sept. 30, 1997	SPS Form 10-Q for the quarter ended Sept. 30, 2017	001-03789	3.01
3.02*	Amended and Restated Bylaws of SPS, dated Jan. 25, 2019	SPS Form 10-K for the year ended Dec. 31, 2018	001-03789	3.02
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	Inline XBRL Schema			
101.CAL	Inline XBRL Calculation			
101.DEF	Inline XBRL Definition			
101.LAB	Inline XBRL Label			
101.PRE	Inline XBRL Presentation			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)			

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SIGNATURES

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

Southwestern Public Service Company

Oct. 29, 2020	By:	/s/ JEFFREY S. SAVAGE
		Jeffrey S. Savage Senior Vice President, Controller (Principal Accounting Officer)
		/s/ BRIAN J. VAN ABEL
		Brian J. Van Abel Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Southwestern Public Service Company	End of 2019/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Southwestern Public Service Company	02 Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 790 South Buchanan Street, Amarillo, TX 79101	
05 Name of Contact Person Jeffrey S. Savage	06 Title of Contact Person Sr. Vice Pres., Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 414 Nicollet Mall, Minneapolis, MN 55401	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(612) 330-5658	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Jeffrey S. Savage	Jeffrey S. Savage	03/30/2020
02 Title Senior Vice President, Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

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LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

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GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey S. Savage
Senior Vice President and Controller
414 Nicollet Mall
Minnespolis, MN 55401

1800 Larimer Street
Denver, CO 80202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

New Mexico, 1921

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Southwestern Public Service Company (SPS) is an operating utility engaged primarily in the generation, purchase, transmission, distribution, and sale of electricity with operations in the state of Texas and New Mexico.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Southwestern Public Service Company (SPS) is a wholly-owned subsidiary of Xcel Energy, Inc.

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CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President	David T. Hudson	290,000
2	Chairman of the Board, Chief Executive Officer	Ben Fowke	173,831
3	Executive VP, Chief Financial Officer	Robert C. Frenzel	83,697
4	Executive VP	Kent T. Larson	79,834
5	Executive VP, General Counsel	Scott M. Wilensky	76,388
6	Executive VP, Chief Customer and Innovations	Brett Carter	70,820
7	Senior VP, Chief Human Resources Officer	Darla Figoli	60,499
8	Executive VP	David L. Eves	59,875
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14	Salaries represent Southwestern Public Service Co.		
15	allocation of officers' salaries greater than $50,000		
16	for the period of time that was served as an		
17	officer for Southwestern Public Service Co.		
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DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	See footnote	
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FOOTNOTE DATA

Schedule Page: 106 Line No.: 1 Column: a

FERC Electric Tariff, First Revised Volume No. 1. (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER08-313-005 - SPS filing to implement a transmission formula rate. (Accession No. 20071210-0247.) Commission Order approving uncontested settlement to implement a transmission formula rate, except the issue of classifying radial transmission facilities, issued December 2, 2009, effective January 1, 2009 - 129 FERC ¶ 61,193 (2009) (Accession No. 20091202-3038.)
FERC Electric Tariff, First Revised Volume No. 1. (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER08-313-002, 003, 004; ER08-923-001, 002, 003; ER08-1307-001, 002; ER08-1308-002, 003, 006; ER08-1357-001, 002; ER08-1358-001, 002; ER08-1359-001, 002 - Settlement filed June 30, 2010 resolving all the remaining issues in the above dockets. Specifically, issues regarding the classification of certain SPS transmission facilities referred to as radial lines (Accession No. 20100701-0022.) Commission Order approving settlement, issued August 26, 2010 - 132 FERC ¶ 61,170 (2010) (Accession No. 20100826-3005.)
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 (Xcel Energy Operating Companies Joint Open Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.) Compliance Filing - corrected certificates of concurrence to the Xcel Energy Operating Companies Joint OATT.	ER10-2075 - Baseline Electronic Tariff Filing of the Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Second Revised Volume No. 1 and Related Tariff Records (Accession No. 20100730-5185.) Amended filing on September 28, 2010 (Accession No. 20100928-5287.) Letter order accepting filing and amendment issued October 25, 2010 effective July 30, 2010 (Accession No. 20101025-3018.)
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER11-114 - SPS submitted revised tariff records contained in Attachment O-SPS to the Xcel Energy Operating Companies Joint OATT. Certain terms and conditions of the settlement filed June 30, 2010 in Docket ER08-313 referenced above required changes to the SPS Transmission Formulaic Rates compared to the formula template currently on file (Accession No. 20101014-5060.) Letter order approving the revised tariff sheets issued December 21, 2010 (Accession No. 20101221-3035.)
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER11-3505 - SPS submitted revised Attachment O-SPS formula rate template. The revised template converts the SPP Base Plan revenue requirement calculation from a historical basis to a projected basis along with a corresponding true-up to actual costs. The SPP Base Plan Upgrade revenue requirement is a component of of the SPS Annual Transmission Revenue Requirement (Accession No. 20110503-5076.) Letter order approving the revised tariff sheets issued July 1, 2011 effective July 5, 2011 (Accession No. 20110701-3027.)
Second Revised FERC Rate Schedule No. 102, Tariff ID 1000 (Public Service Company of New Mexico)	ER10-260 - SPS submitted revisions to Interconnection Agreement between SPS and Public Service Company of New Mexico and to change the rates for interruptible power from a fixed production rate to a formula rate (Accession No. 20100204-0004.) Letter order issued January 5, 2010 accepting revised Interconnection Agreement and formula rate effective November 1, 2009 (Accession No. 20100105-3030.)
FERC Electric Rate Schedule No. 102, Tariff ID 1000	ER11-3442 - Revised Formula Rate Template for

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(Public Service Company of New Mexico)	Interruptible Power Service to Public Service Company of New Mexico (Accession No. 20110427-5155.) Letter order issued June 21, 2011 accepting the revised formula rate template effective January 1, 2010 (Accession No. 20110621-3042.)
SPS FERC Third Revised Rate Schedule Nos. 114, 115, 116, and 117, Tariff ID 1000. (Central Valley Electric Cooperative, Inc., Farmers Electric Cooperative of New Mexico, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc., respectively. Referred to as the New Mexico Cooperatives.)	EL05-19-000, et al., and ER05-168-000, et al. Offer of settlement dated January 19, 2010 (Accession No. 20100119-0048.) Commission Order approving uncontested settlement issued on June 22, 2010 - 131 FERC ¶ 61,260 (2010) (Accession No. 20100622-3002.)
FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	ER11-4082 - Revised Formula Rate Template for Full Requirements Power Service to Central Valley Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)
FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	ER11-4083 - Revised Formula Rate Template for Full Requirements Power Service to Farmers Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)
FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	ER11-4084 - Revised Formula Rate Template for Full Requirements Power Service to Lea County Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)
FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	ER11-4085 - Revised Formula Rate Template for Full Requirements Power Service to Roosevelt County Electric Cooperative, Inc. (Accession No. 20110721-5000.) Letter Order issued September 8, 2011 accepting the the revised formula rate, effective October 1, 2011. (Accession No. 20110908-3004.)
SPS FERC Electric Rate Schedule Second Revised No. 118, Tariff ID 1000. (Wholesale Full Requirements Service to Cap Rock Energy Corporation, now Sharyland Utilities.)	EL05-19-000, et al., and ER05-168-000, et al. Offer of settlement dated July 7, 2010 (Accession No. 20100708-0001.) Commission Order approving uncontested settlement issued on December 20, 2010 - 133 FERC ¶ 61,243 (2010) (Accession No. 20101220-3044.)
FERC Electric Rate Schedule No. 118, Tariff ID 1000 (Sharyland Utilities)	ER11-2921 - Revised Formula Rate Template for Full Requirements Power Service to Sharyland Utilities (Accession No. 20110218-5139.) Letter Order issued April 18, 2011 accepting the revised formula rate template, effective August 1, 2010. (Accession No. 20110418-3029.)
FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	EL05-19-000, ER05-168-000 and ER06-274-000 - Offer of uncontested partial settlement (Accession No. 20071204-0162.) Commission Order approving uncontested partial settlement subject to modification issued on April 21, 2008 - 123 FERC ¶ 61,054 (2008) (Accession No. 20080421-3030.)
FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER10-1426 - Revised Formula Rate Template for Partial Requirements Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20100611-0216.)

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	Letter order issued August 3, 2010 accepting the revised formula rate template, effective July 1, 2008 (Accession No. 20100803-3036.)
FERC Electric Rate Schedule No. 132, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER11-3228 - Revised Formula Rate Template for Partial Requirements Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20110330-5101.) Letter Order issued May 4, 2011 accepting the revised formula rate template, effective January 1, 2010 (Accession No. 20110504-3040.)
First Revised FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER10-515 - Revised Formula Rate Template for Full Requirements Service to West Texas Municipal Power Agency (Accession No. 20091231-0038.) Letter order issued February 18, 2010 accepting the Revised Transaction Agreement & Master Power and Sale Agreement, including the formula rate template, effective January 1, 2010 (Accession No. 20100218-3058.) (Accession No. 20100218-3058.)
FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER11-3598 - Revised Formula Rate Template for Total Requirements Power Service to West Texas Municipal Power Agency (Accession No. 20110519-5016.) Letter Order issued June 24, 2011 accepting the revised formula rate template, effective January 1, 2010 (Accession No. 20110624-3044.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative, Inc.)	ER12-1122 - Expanded Electric Rate Schedule for Partial Revenue Requirements to Golden Spread Electric (Accession No. 20120221-5133.) Letter Order issued April 17, 2012 accepting the expanded service and formula rate template, effective April 20, 2012 (Accession No. 20120417-3003.)
FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	ER13-1451 - Revised Formula Rate Template for Full Requirements Power Service to Central Valley Electric Cooperative, Inc. (Accession No. 20130510-5095.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3018.)
FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	ER13-1452 - Revised Formula Rate Template for Full Requirements Power Service to Lea County Electric Cooperative, Inc. (Accession No. 20130510-5096.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3019.)
FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	ER13-1453 - Revised Formula Rate Template for Full Requirements Power Service to Roosevelt County Electric Cooperative, Inc. (Accession No. 20130510-5097.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3021.)
FERC Electric Rate Schedule No. 118. Tariff ID 1000 (Sharyland Utilities)	ER13-1454 - Revised Formula Rate Template for Full Requirements Power Service to Sharyland Utilities (Accession No. 20130510-5098.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3020.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER13-1455 - Revised Formula Rate Template for Full Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20130510-5099.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012

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	(Accession No. 20130702-3022.)
FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER13-1456 - Revised Formula Rate Template for Full Requirements Power Service to West Texas Municipal Power Agency (Accession No. 20130510-5100.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3023.)
FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	ER13-1458 - Revised Formula Rate Template for Full Requirements Power Service to Farmers Electric Cooperative, Inc. (Accession No. 20130510-5102.) Letter Order issued July 2, 2013 accepting the revised formula rate template, effective January 1, 2012 (Accession No. 20130702-3024.)
FERC Electric Rate Schedule No. 114, Tariff ID 1000 (Central Valley Electric Cooperative, Inc.)	ER14-186 - Revised Formula Rate Template for Requirements Power Service to Central Valley Electric Cooperative, Inc. (Accession No. 20131028-5001.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3017.)
FERC Electric Rate Schedule No. 115, Tariff ID 1000 (Farmers Electric Cooperative of New Mexico, Inc.)	ER14-187 - Revised Formula Rate Template for Requirements Power Service to Farmers Electric Cooperative, Inc. (Accession No. 20131028-5002.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3018.)
FERC Electric Rate Schedule No. 116, Tariff ID 1000 (Lea County Electric Cooperative, Inc.)	ER14-188 - Revised Formula Rate Template for Requirements Power Service to Lea County Electric Cooperative, Inc. (Accession No. 20131028-5003.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3019.)
FERC Electric Rate Schedule No. 117, Tariff ID 1000 (Roosevelt County Electric Cooperative, Inc.)	ER14-189 - Revised Formula Rate Template for Requirements Power Service to Roosevelt County Electric Cooperative, Inc. (Accession No. 20131028-5004.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3020.)
FERC Electric Rate Schedule No. 118, Tariff ID 1000 (Sharyland Utilities)	ER14-190 - Revised Formula Rate Template for Requirements Power Service to Sharyland Utilities (Accession No. 20131028-5005.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3021.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER14-192 - Revised Formula Rate Template for Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20131028-5007.) Commission Order approving revised formula rate template issued December 27, 2013 - 145 FERC ¶ 61,281 (2013) (Accession No. 20131227-3016.)
FERC Electric Rate Schedule No. 137, Tariff ID 1000 (West Texas Municipal Power Agency)	ER14-191 - Revised Formula Rate Template for Requirements Power Service to West Texas Municipal Power Agency (Accession No. 20131028-5006.) Letter Order issued December 27, 2013 accepting the revised formula rate template, effective January 1, 2013 (Accession No. 20131227-3022.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000	ER14-2921 - Revised Wholesale Fuel Cost and Economic

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(Golden Spread Electric Cooperative)	Purchased Power Adjustment Clause and Revised Formula Rate Template for Partial Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20140922-5086.) Amended filing (Accession No. 20141007-5134.) Letter Order issued November 19, 2014 accepting revised template, effective March 1, 2014 (Accession No. 20141119-3046.)
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency)	ER14-2923 - Revised Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause and Revised Formula Rate Template for Requirements Power Service to Central Valley Electric Cooperative, Inc., Farmers' Electric Cooperative of New Mexico, Inc., Lea County Electric Cooperative, Inc., Roosevelt County Electric Cooperative, Inc., and West Texas Municipal Power Agency (Accession No. 20140922-5088.) Amended filing (Accession No. 20141007-5136.) Letter Order issued November 19, 2014 accepting revised template, effective March 1, 2014 (Accession No. 20141119-3045.)
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency)	ER15-561 - Revised Formula Rate Template for Requirements Power Service to Central Valley Electric Cooperative, Inc., Farmers' Cooperative of New Mexico, Inc., Lea County Electric Cooperative, Inc., Roosevelt County Electric Cooperative, Inc., and West Texas Municipal Power Agency (Accession No. 20141203-5058.) Letter Order issued January 28, 2015 accepting revised template, effective January 1, 2014 (Accession No. 20150128-3055.)
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER15-562 - Revised Formula Rate Template for Partial Requirements Power Service to Golden Spread Electric Cooperative, Inc. (Accession No. 20141203-5059.) Letter Order issued January 28, 2015 accepting revised template, effective January 1, 2014 (Accession No. 20150128-3054.)
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	ER-15-949 - SPS CP Filing for Requirements Customers (Accession No. 20150130-5301). Offer of Settlement filed August 28, 2015 (Accession No. 20150828-5323). Letter Order issued October 29, 2015 accepting uncontested settlement re Golden Spread Electric Cooperative, Inc. et. al. (Accession No 20151029-3063). Compliance filing to implement tariff revisions as detailed in the Offer of Settlement (Accession No. 20151214-5234). Letter Order issued January 29, 2016 accepting revised templates (Accession No. 20160129-3034).
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	EL05-19, ER05-168, ER06-274, EL05-151, EL12-59, EL13-78, EL15-8, ER14-192, and ER15-949 - Consolidation of Affected Dockets and Offer of Settlement (Accession No. 20150828-5323). Letter Order issued October 29, 2015 accepting uncontested settlement re Golden Spread Electric Cooperative, Inc. et. al. (Accession No 20151029-3063).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001 (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER16-236 - Revisions to the tariff records to modify the SPS Transmission Formula Rates included in the Xcel Energy Tariff, dated November 2, 2015 to modify the manner in which SPS calculates average Accumulated Deferred Income Tax balances, in order to comply with Section 1.167(l)-1(h)(6)(ii) of IRS regulations, effective January 1, 2016 (Accession No. 20151102-5207).

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	Additional revisions to the tariff records, in response to December 23, 2015 Deficiency Letter dated February 12, 2016 (Accession No. 20160212-5061). Order accepting tariff revisions, subject to conditions, dated April 12, 2016 (Accession No. 20160412-3053). Compliance Filings to implement tariff revisions effective January 1, 2016, and due to the transition to a new electronic tariff software product, the tariff revisions needed to also be effective April 16, 2016 (Docket No. ER16-1686), dated May 12, 1012 (Accession Nos. 20160512-5197 and 20160512-5202). Letter order accepting filings issued August 9, 2016 effective January 1, 2016 and April 16, 2016 (Accession No. 20160809-3024.)
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER16-512 - Compliance filing to implement changes to Transmission Formula Rate Template associated with uncontested settlement in Docket No. ER05-19, et. al. (Accession No. 20151029-3063). Letter Order issued January 29, 2016 accepting compliance filing (Accession No. 20160129-3036).
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	ER16-520 - Revised formula rate template for Requirements customers to include a calculation to provide a rate base credit for certain unfunded reserves, dated December 14, 2015 (Accession No. 20151214-5245). Letter order issued January 29, 2016 approving filing effective January 1, 2016 (Accession No. 20161029-3035).
FERC Electric Rate Schedule No. 135, Tariff ID 1000 (Golden Spread Electric Cooperative)	ER16-920 - Filing to correct certain metadata associated with eTariff records filed in Docket ER13-1455 (Accession No. 20160210-5050). Amended filing to change effective date to April 20, 2012 (Accession No. 20160422-5144). Letter order issued June 9, 2016 approving filing effective April 20, 2012 (Accession No. 20160609-3042).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER16-1420 - Administrative filing to re-Baseline the Tariff Records currently filed under SPS's Tariff ID 2000 (SPS Transmission Tariffs) to new Tariff ID 2001 (Transmission and Service Agreements Tariff). This filing is to facilitate the transition to a new electronic tariff filing software, dated April 15, 2016 (Accession No. 20160415-5088). Letter order accepting filing issued June 7, 2016, effective April 16, 2016 (Accession No. 20160607-3006).
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	ER16-1431 - Administrative filing to re-Baseline the Tariff Records currently filed under SPS's Tariff ID 1000 (SPS Market Tariffs) to new Tariff ID 1001 (Production Tariffs). This filing is to facilitate the transition to a new electronic tariff filing software, dated April 15, 2016 (Accession No. 20160415-5177). Letter order accepting filing issued June 7, 2016, effective April 16, 2016 (Accession No. 20160607-3006).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER16-2597 and ER16-2598 - Revisions to the Tariff Records to modify the SPS Transmission Formula Rates included in the Xcel Energy Tariff, dated September 16, 2016, to reflect a new SAP general ledger accounting system adopted by Xcel Energy Services Inc. and the Xcel Energy Operating Companies for fiscal year 2016, and other ministerial clean-up revisions to Attachment O-SPS (Accession Nos. 20160916-5048 and 20160916-5052) . Letter orders accepting tariff revisions effective January 1, 2016 April 16, 2016, dated November 9, 2016 (Accession Nos.

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FOOTNOTE DATA

	20161109-3044 and 20161109-3045).
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 135, and 137, Tariff ID 1000 and 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, Golden Spread Electric Cooperative, West Texas Municipal Power Agency)	ER17-236 and ER17-238 - Revisions to the Production Tariff records dated October 31, 2016 to reflect a new SAP general ledger accounting system adopted by Xcel Energy Services Inc. and the Xcel Energy Operating Companies for fiscal year Operating Companies for fiscal year 2016, and 2016, and other ministerial clean-up revisions (Accession Nos. 20161031-5200 and 20161031-5222). Submission of additional revisions to the Production Tariff records dated December 23, 2016 (Accession Nos. 20161223-5096 and 20161223-5102). Letter order accepting tariff revisions effective January 1, 2016 and April 16, 2016, dated February 15, 2017 (Accession No. 20170215-3030).
FERC Electric Rate Schedule No. 136, Tariff ID 1001 (Tri-County Electric Cooperative, Inc.)	ER17-267 - Revisions to Transaction Agreement with Tri-County Electric Cooperative, Inc. to convert to a Production Formula Rate, dated November 1, 2016 (Accession No. 20161101-5097). Letter order accepting filing effective January 1, 2017, dated February 17, 2017 (Accession No. 20170217-3013).
FERC Electric Rate Schedule Nos. 114, 115, 116, 117, 136, and 137, Tariff ID 1001 (Central Valley Electric Cooperative, Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Roosevelt County Electric Cooperative, West Texas Municipal Power Agency, Tri-County Electric Cooperative, Inc.)	ER18-228 - Revisions to the Production Formula Rate Template Implementation Procedures to update the wholesale depreciation rates used to calculate the depreciation expense, based on a new depreciation study, effective January 1, 2018. (Accession No. 20171101-5294). Offer of Settlement filed January 7, 2019 (Accession No. 20190107-5000).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER18-1521 - Request for waiver of Formula Rate Implementation Procedures applicable to SPS's Attachment O in the Xcel Energy Tariff. The waiver allows SPS to revise the federal income rate input in its 2018 projected net revenue requirements to reflect the reduction in the federal rate. (Accession No. 20180504-5171). Order granting request for waiver effective January 1, 2018 (Accession No. 20180531-5131).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER18-2410 - Revisions to the tariff records to the Xcel Energy Tariff to clearly identify the calculation of the operation and maintenance expenses charged to interconnecting generators under Section 10.5 of the pro forma Large Generator Interconnection Agreement and Section 4.1.2 of the pro forma Small Generator Interconnection Agreement (Accession No. 20180911-5120). Order accepting tariff revisions effective January 1, 2019, dated March 15, 2019 (Accession No. 20190315-3054).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER18-2319 - Revisions to the tariff records to modify the calculation of Accumulated Deferred Income Tax ("ADIT") balances in the Transmission Formula Rate included in the Xcel Energy Tariff to comply with Section 1.167(l)-1(h)(6)(ii) of the IRS regulations. The revisions eliminate the "two step averaging" in calculating the projected annual transmission revenue requirement, estimated rates and formula rate true-up. (Accession No. 20180827-5098). Order on Paper Hearing and Accepting Proposed Tariff Revisions effective January 1, 2019, that will apply to true-up calculations to reflect the revisions as of June 27, 2018 (Accession No.

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	20181220-2032).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER19-404 - Revisions to the tariff records to the Xcel Energy Tariff to revise Attachment O-SPS as follows: 1) update transmission depreciation rates; 2) revise the Template's Base Upgrade revenue requirement calculation to use the weighted average transmission depreciation rate; 3) revise the Template to recover certain wholesale regulatory commission expenses; 4) correct the allocation of transmission-specific ADIT; and 5) revise the methodology for calculating ADIT to amortize the "excess" ADIT caused by the TCJA and include the amortization in the income tax calculation, effective February 1, 2019 (Accession No. 20181127-5093).
FERC Electric Tariff, Second Revised Volume No. 1, Tariff ID 2000 and 2001, (Xcel Energy Operating Companies Joint Open Access Transmission Tariff, Attachment O - Southwestern Public Service Company Formulaic Rates.)	ER19-675 - Revisions to the tariff records to the Xcel Energy Tariff to revise Attachment O-SPS to establish a new formula rate mechanism to calculate a monthly Wholesale Distribution Service Charge applied to SPS' transmission service customers that take delivery of energy from SPS at distribution voltage (less than 69 kV) delivery points (Accession No. 20181221-5281). (Accession No. 20181221-5281). Order accepting and suspending proposed tariff revisions effective August 1, 2019 and establishing hearing and Settlement Judge procedures (Accession No. 20190228-3016).

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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20181203-5188	12/03/2018	ER08-313-000	Information Filing: Annual Update of	Xcel Energy Operating Companies
2				Transmission Formula Rate, under	FERC Electric Tariff, Second Revised
3				ER08-313, et al.	Volume No. 1 - Attachment O - SPS
4					Southwestern Public Service
5					Company Formulaic Rates
6					
7	20180524-5099	05/25/2017	EL05-19-000	Informational Filing: Annual Update of	FERC Electric Rate Schedule No. 114
8			ER05-168-000	Rates for Service to Central Valley	FERC Electric Rate Schedule No. 115
9			ER10-515-000	Cooperative Inc., Farmers Electric	FERC Electric Rate Schedule No. 116
10			ER17-267-000	of New Mexico Inc., Lea County	FERC Electric Rate Schedule No. 117
11				Cooperative Inc., Roosevelt County	FERC Electric Rate Schedule No. 118
12				Cooperative Inc., Tri-County Electric	FERC Electric Rate Schedule No. 136
13				Inc., and West Texas Municipal Power	FERC Electric Rate Schedule No. 137
14				(The Annual Update informational filing	
15				the calculation of estimated rates for	
16				these customers for the upcoming rate	
17				July 1, 2018 to June 30, 2019).	
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INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

The following important changes have been accumulated during 2019:

1. Franchise

Amarillo, TX – Utility Electric – Expiration 5/6/2029

Lefors, TX – Utility Electric – Expiration 5/31/2039

Panhandle, TX – Utility Electric – Expiration 6/14/2039

Plainview, TX – Utility Electric – Expiration 7/31/2029

Channing, TX – Utility Electric – Expiration 8/31/2039

Idalou, TX – Utility Electric – Expiration 10/11/2039

Littlefield, TX – Utility Electric – Expiration 10/28/2029

Fritch, TX – Utility Electric – Expiration 10/31/2024

Ropesville, TX – Utility Electric – Expiration 12/29/2039

Stratford, TX – Utility Electric – Expiration 3/7/2031

2. Acquisitions

None

3. Purchase or sale of an operating system

None

4. Important leaseholds acquired or given, assigned or surrendered

None

5. Important extension or reduction of transmission or distribution system

None

6. Obligations incurred as a result of securities or assumption of liabilities

See Note 3 of the Financial Statements on page 123 for disclosures regarding short-term borrowings, long-term debt and other financing instruments.

7. Changes in articles of incorporation and amendments to charter

None

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

8. Wage scale changes

Union Employees – 2.5% increase effective 11/1/2019.

Non-Union employees – Merit base increase of 3.00 percent effective March 16, 2019.

9. Legal proceedings

See Note 6 of the Financial Statements on page 123 for further information on material legal proceedings.

10. Other materially important transactions with associates

None

11. (Reserved)

12. Important changes

None

13. Changes in officers, directors, major security holders and voting powers

Mary Schell resigned as Assistant Treasurer on May 3, 2019

Jodee Marble resigned as Assistant Corporate Secretary on June 3, 2019

Patricia L. Martin elected as Assistant Treasurer on October 1, 2019

Gioia M. Gentile elected as Assistant Secretary on September 9, 2019

14. Cash management programs

N/A as proprietary capital ratio is greater than 30%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	8,974,159,799	7,224,210,989
3	Construction Work in Progress (107)	200-201	486,406,071	849,058,368
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,460,565,870	8,073,269,357
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,480,929,856	2,315,941,276
6	Net Utility Plant (Enter Total of line 4 less 5)		6,979,636,014	5,757,328,081
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,979,636,014	5,757,328,081
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,422,200	4,422,200
19	(Less) Accum. Prov. for Depr. and Amort. (122)		431,743	389,211
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		3,209,807	2,170,934
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		12,635,800	15,794,752
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		19,836,064	21,998,675
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	43,254,838
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		100,500	100,600
38	Temporary Cash Investments (136)		16,544,204	678,238
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		64,916,760	61,446,320
41	Other Accounts Receivable (143)		44,181,177	49,470,885
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,303,953	5,614,497
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		4,199,875	10,490,267
45	Fuel Stock (151)	227	6,314,902	8,202,732
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	20,798,740	20,810,571
49	Merchandise (155)	227	153,261	188,238
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	3,753,904	4,684,859

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		3,844,382	2,961,246
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		941,550	674,447
60	Rents Receivable (172)		608,855	701,102
61	Accrued Utility Revenues (173)		115,069,769	114,488,630
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		27,637,114	33,612,156
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		12,635,800	15,794,752
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		291,125,240	330,355,880
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		23,201,848	20,388,992
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	336,968,150	360,121,131
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	23,209,472	10,509,661
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		21,863,392	22,671,006
82	Accumulated Deferred Income Taxes (190)	234	248,572,823	101,395,180
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		653,815,685	515,085,970
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,944,413,003	6,624,768,606

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FOOTNOTE DATA

Schedule Page: 110 Line No.: 2 Column: c

Includes operating leases in accordance with Accounting Standards Codification (ASC) Topic 842 and FERC Docket No. AI19-1-000. See Note 7 to the Financial Statements on page 123 for leasing disclosures.

Account 101.1	
Finance Lease Asset	$ -
Operating Right of Use Asset	$ 522,437,456
Total	$ 522,437,456

Schedule Page: 110 Line No.: 52 Column: c

The balance is comprised of Texas Renewable Energy Credit Allowances of $3,753,904

Schedule Page: 110 Line No.: 52 Column: d

The balance is comprised of Texas Renewable Energy Credit Allowances of $4,684,859

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	100	100
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		362,132,083	362,132,084
7	Other Paid-In Capital (208-211)	253	1,997,779,212	1,579,192,171
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	9,033,435	9,033,435
11	Retained Earnings (215, 215.1, 216)	118-119	534,982,517	605,725,195
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-1,412,436	-1,390,415
16	Total Proprietary Capital (lines 2 through 15)		2,884,448,041	2,536,625,700
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,100,000,000	1,800,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	350,000,000	350,000,000
22	Unamortized Premium on Long-Term Debt (225)		8,724,223	9,036,717
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		15,791,032	12,577,728
24	Total Long-Term Debt (lines 18 through 23)		2,442,933,191	2,146,458,989
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		495,338,022	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	1,369,289
29	Accumulated Provision for Pensions and Benefits (228.3)		62,423,000	88,954,228
30	Accumulated Miscellaneous Operating Provisions (228.4)		395,364	609,192
31	Accumulated Provision for Rate Refunds (229)		3,900,169	0
32	Long-Term Portion of Derivative Instrument Liabilities		12,819,107	16,383,835
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		77,293,282	32,422,529
35	Total Other Noncurrent Liabilities (lines 26 through 34)		652,168,944	139,739,073
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	42,000,000
38	Accounts Payable (232)		176,114,758	198,349,988
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		20,393,121	19,853,351
41	Customer Deposits (235)		5,950,059	6,975,006
42	Taxes Accrued (236)	262-263	41,219,513	42,497,226
43	Interest Accrued (237)		26,206,970	25,766,686
44	Dividends Declared (238)		46,282,075	45,159,800
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		5,371,685	5,034,489
48	Miscellaneous Current and Accrued Liabilities (242)		3,515,135	2,184,608
49	Obligations Under Capital Leases-Current (243)		27,099,433	0
50	Derivative Instrument Liabilities (244)		16,506,049	19,948,560
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		12,819,106	16,383,835
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		355,839,692	391,385,879
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	104,864	157,285
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	15,572,967	13,239,647
60	Other Regulatory Liabilities (254)	278	675,890,874	678,989,897
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	1,098,369	1,127,055
63	Accum. Deferred Income Taxes-Other Property (282)		721,841,421	634,112,655
64	Accum. Deferred Income Taxes-Other (283)		194,514,640	82,932,426
65	Total Deferred Credits (lines 56 through 64)		1,609,023,135	1,410,558,965
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,944,413,003	6,624,768,606

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 26 Column: c

Includes operating leases in accordance with Accounting Standards Codification (ASC) Topic 842 and FERC Docket No. AI19-1-000. See Note 7 to the Financial Statements on page 123 for leasing disclosures.

Schedule Page: 112 Line No.: 49 Column: c

Includes operating leases in accordance with Accounting Standards Codification (ASC) Topic 842 and FERC Docket No. AI19-1-000. See Note 7 to the Financial Statements on page 123 for leasing disclosures.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,772,552,889	1,895,673,382		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,064,391,128	1,258,033,746		
5	Maintenance Expenses (402)	320-323	59,870,268	59,743,150		
6	Depreciation Expense (403)	336-337	196,451,788	168,450,121		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	619,059	1,943		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	27,896,392	27,401,099		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		13,518,482	8,751,052		
13	(Less) Regulatory Credits (407.4)		18,233,658	9,078,986		
14	Taxes Other Than Income Taxes (408.1)	262-263	72,171,786	67,974,652		
15	Income Taxes - Federal (409.1)	262-263	-3,649,019	15,232,455		
16	- Other (409.1)	262-263	610,012	2,554,065		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	205,332,215	95,466,283		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	176,978,891	74,143,754		
19	Investment Tax Credit Adj. - Net (411.4)	266	-52,421	-52,421		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		-5	11,863		
23	Losses from Disposition of Allowances (411.9)		873,526	1,335,403		
24	Accretion Expense (411.10)		2,137,505	1,530,270		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,444,958,177	1,623,187,215		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		327,594,712	272,486,167		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,772,552,889	1,895,673,382					2
						3
1,064,391,128	1,258,033,746					4
59,870,268	59,743,150					5
196,451,788	168,450,121					6
619,059	1,943					7
27,896,392	27,401,099					8
						9
						10
						11
13,518,482	8,751,052					12
18,233,658	9,078,986					13
72,171,786	67,974,652					14
-3,649,019	15,232,455					15
610,012	2,554,065					16
205,332,215	95,466,283					17
176,978,891	74,143,754					18
-52,421	-52,421					19
						20
						21
-5	11,863					22
873,526	1,335,403					23
2,137,505	1,530,270					24
1,444,958,177	1,623,187,215					25
327,594,712	272,486,167					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		327,594,712	272,486,167		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		124,413	202,737		
34	(Less) Expenses of Nonutility Operations (417.1)		191,622	210,409		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		4,544,072	826,207		
38	Allowance for Other Funds Used During Construction (419.1)		26,806,764	19,102,029		
39	Miscellaneous Nonoperating Income (421)		-353,173	107,977		
40	Gain on Disposition of Property (421.1)		61,254	6,794		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,991,708	20,035,335		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			13,700		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,433,231	2,100,873		
46	Life Insurance (426.2)		-97,708	-34,743		
47	Penalties (426.3)		187,236	32,815		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		645,905	504,416		
49	Other Deductions (426.5)		495,283	208,972		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,663,947	2,826,033		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	28,485	22,400		
53	Income Taxes-Federal (409.2)	262-263	333,073	-2,444,727		
54	Income Taxes-Other (409.2)	262-263	22,233	-28,773		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1	3,041,319		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2	731,155		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		383,790	-140,936		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		27,943,971	17,350,238		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		96,694,431	79,516,495		
63	Amort. of Debt Disc. and Expense (428)		1,447,980	1,169,096		
64	Amortization of Loss on Reaquired Debt (428.1)		807,614	807,614		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		862,225	1,071,156		
68	Other Interest Expense (431)		4,978,442	2,910,785		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,319,331	8,958,966		
70	Net Interest Charges (Total of lines 62 thru 69)		92,471,361	76,516,180		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		263,067,322	213,320,225		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		263,067,322	213,320,225		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 4 Column: c

Includes $16.6 million of demand-side management program expenses.

Schedule Page: 114 Line No.: 4 Column: d

Includes $17.7 million of demand-side management program expenses.

Schedule Page: 114 Line No.: 12 Column: c

TX 47527 TCRF Billings	$ 5,466,386
Hale Excess Over Revenue Requirement	550,365
NM RPS Rider Amort	5,636,914
TX Restruct Recoverable Meter	34,898
NM Z2 Amort	520,490
TX Z2 Amort	1,309,429
	$13,518,482

Schedule Page: 114 Line No.: 12 Column: d

NM RPS Rider Amort	$ 7,348,258
TX Restruct Recoverable Meter	34,898
NM Z2 Amort	135,907
TX Z2 Amort	1,231,989
	$ 8,751,052

Schedule Page: 114 Line No.: 13 Column: c

ARO Reg Credits Electric	$ 2,756,564
Amort of Inc Capital RL	53,949
NM Lg Cust Cap Amort	1,851,317
TX 49831 Cost Deferrals	13,523,666
TX 47527 Settlement-Interest	48,162
	$18,233,658

Schedule Page: 114 Line No.: 13 Column: d

ARO Reg Credits Electric	$ 1,532,213
Amort of Inc Capital RL	53,949
NM Lg Cust Cap Amort	2,109,921
Retail Recovery of Credit Dist. - Funded	(948)
Retail Recovery of PTP Revenue Clawback	527
Retail Recovery of Z2	36,509
TX 47527 Revenue Accrual	5,346,815
	$ 9,078,986

Schedule Page: 114 Line No.: 22 Column: c

Gain-Disposition of SO2 Allowances	$ 59
SO2 Texas Retail Sharing	(16)
SO2 New Mexico Retail Sharing	(32)
Gain-Disposition of REC Allowances	(16)
	$ (5)

Schedule Page: 114 Line No.: 22 Column: d

Gain-Disposition of SO2 Allowances	$ 62
SO2 Texas Retail Sharing	(18)
SO2 New Mexico Retail Sharing	(35)
SO2 Amortization	5,439
Gain-Disposition of REC Allowances	6,415
	$ 11,863

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 22 Column: g

Gain-Disposition of SO2 Allowances	$	59
SO2 Texas Retail Sharing		(16)
SO2 New Mexico Retail Sharing		(32)
Gain-Disposition of REC allowances		(16)
	$	(5)

Schedule Page: 114 Line No.: 22 Column: h

Gain-Disposition of SO2 Allowances	$	62
SO2 Texas Retail Sharing		(18)
SO2 New Mexico Retail Sharing		(35)
SO2 Amortization		5,439
Gain-Disposition of REC Allowances		6,415
	$	11,863

Schedule Page: 114 Line No.: 39 Column: c

Unnatural balance due to interest due to customers related to overcollected deferred fuel balances

Schedule Page: 114 Line No.: 40 Column: c

Sale of distribution service center

Schedule Page: 114 Line No.: 46 Column: c

Income on Company owned life insurance

Schedule Page: 114 Line No.: 46 Column: d

Income on Company owned life insurance

Schedule Page: 114 Line No.: 54 Column: d

Unnatural balances for FERC 409 are relatively common because there is not an account for income tax benefits. Therefore, all income tax benefits and detriments are recorded in current tax expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		605,725,195	541,588,360
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				(90)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			(90)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		263,067,322	213,320,225
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-333,810,000	(149,183,300)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-333,810,000	(149,183,300)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		534,982,517	605,725,195
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		534,982,517	605,725,195
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	263,067,322	213,320,225
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	197,754,274	170,024,867
5	Amortization of Premium, Discount and Debt Expense	2,255,594	1,976,710
6	Amortization of Regulatory Assets and Liabilities	-881,360	-327,935
7	Amortization of Software and Others	27,896,392	27,401,099
8	Deferred Income Taxes (Net)	28,353,323	23,633,381
9	Investment Tax Credit Adjustment (Net)	-52,421	-52,421
10	Net (Increase) Decrease in Receivables	205,227	-15,472,941
11	Net (Increase) Decrease in Inventory	-21,397,888	-16,002,541
12	Net (Increase) Decrease in Allowances Inventory	930,955	5,313
13	Net Increase (Decrease) in Payables and Accrued Expenses	-2,863,693	5,745,985
14	Net (Increase) Decrease in Other Regulatory Assets	4,813,942	9,940,397
15	Net Increase (Decrease) in Other Regulatory Liabilities	17,006,448	26,074,733
16	(Less) Allowance for Other Funds Used During Construction	26,806,764	19,102,029
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Change in Accrued Utility Revenues	-581,139	15,315,207
19	Change in Other Current Assets and Liabilites	-1,987,705	-7,835,715
20	Net Derivative Losses	63,181	63,162
21	Change in Other Noncurrent Liabilites and Deferred Amounts	-14,531,663	11,576,389
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	473,244,025	446,283,886
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-871,197,746	-1,039,880,283
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		-82,100
30	(Less) Allowance for Other Funds Used During Construction	-26,806,764	-19,102,029
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-844,390,982	-1,020,860,354
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Other: Investments in Utility Money Pool	-133,000,000	-285,000,000
55	Other: Repayments from Utility Money Pool	133,000,000	350,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-844,390,982	-955,860,354
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	292,213,366	294,959,848
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions by Parent	426,232,344	336,587,000
65	Other: Borrowings Under Utility Money Pool	296,000,000	595,000,000
66	Net Increase in Short-Term Debt (c)	-42,000,000	42,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	972,445,710	1,268,546,848
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other: Repayment of Utility Money Pool	-296,000,000	-595,000,000
77	Other (Taxes Paid - Share based awards		-31,187
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-332,687,725	-130,776,625
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	343,757,985	542,739,036
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-27,388,972	33,162,568
87			
88	Cash and Cash Equivalents at Beginning of Period	44,033,676	10,871,108
89			
90	Cash and Cash Equivalents at End of period	16,644,704	44,033,676

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company		04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies

General - Southwest Public Service Company (SPS) is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity. SPS is subject to regulation by the Federal Energy Regulatory Commission (FERC) and state utility commissions.

Business and System of Accounts - SPS is a wholly-owned subsidiary of Xcel Energy Inc. that is principally engaged in the generation, purchase, transmission, distribution and sale of electricity. SPS is subject to regulation by the FERC and state utility commissions.

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Deferred financing costs are included as deferred debits in the FERC presentation in contrast to the GAAP presentation in which they are included as a deduction from the carrying amount of long-term debt.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits.
- Unrecognized tax benefits are recorded for temporary adjustments in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to its GAAP presentation as taxes accrued and other noncurrent liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation within the utility plant accounts in the FERC presentation and regulatory liabilities in the GAAP presentation.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for FERC presentation; however the net margin is reported as net sales for GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for FERC presentation and reported as operating expenses for GAAP presentation.
- Income tax expense related to utility operations is shown as a component of utility operating expenses in the FERC presentation, in contrast to its GAAP presentation as a below-the-line deduction from operating income.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP. While for FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Non-service cost components of net periodic benefit costs that are reported on the income statement are recorded as operation expenses in the FERC presentation and as other income, net for GAAP presentation. Non-service costs that are eligible for capitalization are recorded as a component of net utility plant in the FERC presentation and as regulatory assets for GAAP.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by FERC presentation of:

(Millions of Dollars)	Dec. 31, 2019
Balance Sheet	
Net utility assets	$ (348.0)
Current assets	25.7
Current liabilities	125.4
Other long-term assets	229.3
Long-term debt and other long-term liabilities	(218.4)
Statement of Income	
Operating revenues	53.2
Operating expenses	34.1
Other income and deductions	1.0
Interest and finance charges	(5.5)

Use of Estimates — SPS uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — SPS accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, SPS 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 SPS' results of operations, financial condition and cash flows.

See Note 2 for further information.

Income Taxes — SPS accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. SPS defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. SPS uses 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 SPS' tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most 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 investment tax credits (ITCs) related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

SPS 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. SPS recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

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

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

See Note 4 for further information.

Utility Plant and Depreciation — Utility plant is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and allowance for funds used during construction (AFUDC). The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Utility plant 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 utility plant 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.

SPS records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was 2.9% in 2019, 2.9% in 2018 and 2.8% in 2017.

AROs — SPS 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. SPS 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 7 for further information.

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

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

See Note 6 for further information.

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

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties (PRPs) exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for SPS' expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 7 for further information.

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

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

SPS participates in Southwest Power Pool, Inc. (SPP). SPS recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term wholesale sales of excess energy transacted through regional transmission organizations (RTOs) are also recorded on a gross basis. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

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

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

As of Dec. 31, 2019 and 2018, the allowance for bad debts was $5.3 million and $5.6 million, respectively.

Inventory — Inventory is recorded at average cost.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Fair Value Measurements — SPS presents cash equivalents, interest rate derivatives and commodity derivatives at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values (NAVs). For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, SPS 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 5 and 6 for further information.

Derivative Instruments — SPS uses derivative instruments in connection with its utility commodity price and interest rate activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on expected recovery of derivative instrument settlements through fuel and purchased energy cost recovery mechanisms. Interest rate hedging transactions are recorded as a component of interest expense.

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

See Note 5 for further information.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of the commodity trading margins from Public Service Company of Colorado (PSCo) are apportioned to NSP-Minnesota and Southwestern Public Service Company (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 7 for further discussion.

Other Utility Items

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

Alternative Revenue — Certain rate rider mechanisms (including DSM programs) qualify as alternative revenue programs. 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, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

Conservation Programs — SPS has implemented programs in its jurisdictions to assist customers in conserving energy and reducing peak demand on the electric system. These programs include commercial motor, air conditioner and lighting upgrades, as well as residential rebates for participation in air conditioner interruption and home weatherization.

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Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The costs incurred for some demand side management (DSM) programs are deferred as permitted by the applicable regulatory jurisdiction. For those programs, costs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of lost margins 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. SPS recovers approved conservation program costs in base rate revenue or through a rider.

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

Renewable Energy Credits (RECs) — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. SPS reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

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

Segment Information — SPS has only one reportable segment. SPS is a wholly owned subsidiary of Xcel Energy Inc. and operates in the regulated electric utility industry providing wholesale and retail electric service in the states of Texas and New Mexico.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2019 up to Feb. 21, 2020, the date SPS' GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 30, 2020. These financial statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Regulatory Assets and Liabilities

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

Components of regulatory assets:

(Millions of Dollars)	Remaining Amortization Period	Dec. 31, 2019	Dec. 31, 2018
Regulatory Assets			
Pension and retiree medical obligations	Various	$ 210.6	$ 232.0
Excess deferred taxes — Tax cuts and jobs act (TCJA)	Various	53.6	55.8
Recoverable deferred taxes on AFUDC recorded in plant	Plant lives	34.1	27.9
Net AROs (a)	Plant lives	26.9	25.7
Conservation programs (b)	One to two years	0.6	0.1
Other	Various	11.2	18.6
Total regulatory assets		$ 337.0	$ 360.1

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

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

Components of regulatory liabilities:

(Millions of Dollars)	Remaining Amortization Period	Dec. 31, 2019	Dec. 31, 2018
Regulatory Liabilities			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Deferred income tax adjustments and TCJA refunds [a]	Various	$ 541.8	$ 571.9
Gain from asset sales	Various	2.4	2.4
Deferred electric energy costs	Less than one year	81.7	56.6
Other	Various	50.0	48.1
Total regulatory liabilities [b]		$ 675.9	$ 679.0

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

(b) Revenue subject to refund of $3.9 million for 2019 and none for 2018 is included in other current liabilities.

At Dec. 31, 2019 and 2018, SPS' regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, SPS' regulatory assets included $56.5 million and $50.5 million at Dec. 31, 2019 and 2018, respectively, of past expenditures not earning a return. Amounts primarily related to formula rates, losses on reacquired debt and certain rate case expenditures.

3. Borrowings and Other Financing Instruments

Short-Term Borrowings

SPS meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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.

Money pool borrowings for SPS were as follows:

(Millions of Dollars, Except Interest Rates)	Year Ended Dec. 31	
	2019	2018
Borrowing limit	$ 100	$ 100
Amount outstanding at period end	—	—
Average amount outstanding	8	29
Maximum amount outstanding	100	100
Weighted average interest rate, computed on a daily basis	2.42%	1.96%
Weighted average interest rate at end of period	N/A	N/A

Commercial Paper — Commercial paper outstanding for SPS was as follows:

(Millions of Dollars, Except Interest Rates)	Year Ended Dec. 31	
	2019	2018
Borrowing limit	$ 500	$ 400
Amount outstanding at period end	—	42
Average amount outstanding	72	30
Maximum amount outstanding	316	144
Weighted average interest rate, computed on a daily basis	2.68%	2.27%
Weighted average interest rate at end of period	N/A	2.80

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Letters of Credit — SPS may use letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2019 and 2018, there were $2 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, SPS 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 line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreement — In June 2019, SPS entered into an amended five-year credit agreement with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the exception of the following:

- Maturity extended from June 2021 to June 2024; and
- Borrowing limit increased from $400 million to $500 million.

The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of SPS' credit facility:

Debt-to-Total Capitalization Ratio (a)		Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested (b)
2019	2018		
46%	46%	$50	2

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

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

The credit facility has a cross-default provision that SPS will be in default on its borrowings under the facility if SPS or any of its future significant subsidiaries whose total assets exceed 15% of SPS' total assets default on indebtedness in an aggregate principal amount exceeding $75 million.

If SPS 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. As of Dec. 31, 2019, SPS was in compliance with all financial covenants.

SPS had the following committed credit facilities available as of Dec. 31, 2019.

Credit Facility (a)	Drawn (b)	Available
$500	$2	$498

(a) This credit facility matures in June 2024.

(b) Includes letters of credit and outstanding commercial paper.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. SPS had no direct advances on the facility outstanding at Dec. 31, 2019 and 2018.

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Long-Term Borrowings and Other Financing Instruments

Generally, all property of SPS is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long-term debt obligations for SPS as of Dec. 31 (millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	3.30%	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds (b)	4.40	Nov. 15, 2048	300	300
First mortgage bonds (a)	3.75	June 15, 2049	300	—
Unamortized discount			(7)	(4)
Unamortized debt issuance cost			(23)	(20)
Total long-term debt			$ 2,420	$ 2,126

(a) 2019 financing

(b) 2018 financing

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Maturities of long-term debt:

(Millions of Dollars)	
2020	$ —
2021	—
2022	—
2023	—
2024	350

Capital Stock — SPS has the following preferred stock:

Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2019 and 2018
10,000,000	1.00	—

Dividend Restrictions — SPS dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. SPS is required to be current on particular interest payments before dividends can be paid.

SPS' state regulatory commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2019:

Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual [(a)]
Low	High	2019
45.0%	55.0%	54.4%

(a) Excludes short-term debt.

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization [(a)]
$ 535.0million	$ 5.3billion	N/A

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

4. Income Taxes

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

Tax Year(s)	Expiration
2009 - 2013	June 2020
2014 - 2016	September 2020

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). Xcel Energy filed a protest with the IRS. As of Dec. 31, 2019, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of Dec. 31, 2019 no adjustments have been proposed.

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State Audits — SPS is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2019, SPS' 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 — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Uncertainty in Income Taxes — The FERC has not fully adopted the guidance for uncertainty in income taxes. Accordingly, SPS has recorded its unrecognized tax benefits for temporary adjustments, including NOL and tax credit carryforwards, in accounts established for accumulated deferred income taxes.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	December 31, 2019	December 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 3.7	$ 3.0
Unrecognized tax benefit — Temporary tax positions	1.5	1.5
Total unrecognized tax benefit	$ 5.2	$ 4.5

Changes in unrecognized tax benefits:

(Millions of Dollars)	2019	2018
Balance at Jan. 1	$ 4.5	$ 4.3
Additions based on tax positions related to the current year	0.7	0.6
Reductions based on tax positions related to the current year	(0.1)	(0.1)
Additions for tax positions of prior years	0.2	0.1
Reductions for tax positions of prior years	(0.1)	(0.3)
Settlements with taxing authorities	—	(0.1)
Balance at Dec. 31	$ 5.2	$ 4.5

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

(Millions of Dollars)	2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (4.4)	$ (3.8)

As the IRS Appeals and federal audit progresses and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $3.7 million in the next 12 months.

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

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2019	2018
Receivable (payable) for interest related to unrecognized tax benefits at Jan. 1	$ 0.7	$ 0.5
Interest income related to unrecognized tax benefits	—	0.2
Receivable for interest related to unrecognized tax benefits at Dec. 31	$ 0.7	$ 0.7

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No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2019 and 2018.

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

(Millions of Dollars)	2019	2018
Federal tax credit carryforwards	$ 31.7	$ 7.4
State NOL carryforwards	1.2	2.9

Federal carryforward periods expire between 2024 and 2039 and state carryforward periods expire between 2025 and 2036.

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

Effective income tax rate for years ended Dec. 31:

	2019	2018 (a)
Federal statutory rate	21.0%	21.0%
State income tax on pretax income, net of federal tax effect	2.2%	2.3%
Increases (decreases) in tax from:		
Wind production tax credits	(7.9)	—
Plant regulatory differences (b)	(5.0)	(4.8)
Amortization of excess nonplant deferred taxes	(0.9)	(1.2)
Other tax credits, net of NOL & tax credit allowances	(0.6)	(0.7)
Adjustments attributable to tax returns	(0.1)	(1.5)
Other, net	0.2	0.3
Effective income tax rate	8.9%	15.4%

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

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions.

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

(Millions of Dollars)	2019	2018
Current federal tax (benefit) expense	$ (4.0)	$ 12.3
Current state tax expense	0.6	2.3
Current change in unrecognized tax expense	0.7	0.7
Deferred federal tax expense	22.4	20.0
Deferred state tax expense	6.0	3.6
Deferred income tax credits	(0.1)	(0.1)
Other	—	0.1
Total income tax expense	$ 25.6	$ 38.9

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

(Millions of Dollars)	2019	2018
Deferred tax expense (benefit) excluding items below	$ 52.1	$ 45.8
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(23.8)	(22.0)
Tax benefit (expense) allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	0.1	(0.2)
Deferred tax expense	$ 28.4	$ 23.6

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

(Millions of Dollars)	2019	2018 (a)
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 854.3	$ 772.8
Operating lease assets	115.8	—
Regulatory assets	(85.7)	(90.9)
Pension expense	33.1	32.3
Other	—	$ 4.0
Total deferred tax liabilities	$ 917.5	$ 718.2
Deferred tax assets:		
Differences between book and tax bases of property	$ 87.5	$ 84.9
Operating lease liabilities	115.8	—
Tax credit carryforward	31.7	7.4
Regulatory liabilities	(24.1)	(23.2)
Deferred fuel costs	18.3	12.7
Other employee benefits	5.8	5.6
NOL carryforward	0.1	0.2
Other	13.5	13.8
Total deferred tax assets	248.6	101.4
Net deferred tax liability	$ 668.9	$ 616.8

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

In December 2017, SPS remeasured our deferred tax assets and liabilities to the new federal corporate income tax rate of 21%. After filing the 2017 tax return, we completed a final remeasurement of our 2017 deferred tax assets and liabilities to the new corporate tax rate. SPS received guidance from some jurisdictions in 2018 and started the amortization of the deficient and excess ADIT for those jurisdictions. The Protected ADITs, which are required by IRS normalization rules to be provided to customers, are amortized according to the rules of the Average Rate Assumption Method (ARAM) with amortization occurring over the remaining book life of the individual assets. The Unprotected ADITs, are amortized according to each jurisdiction. The Nonplant Unprotected have amortization periods of 5 years. While, Plant Unprotected will use ARAM.

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The amount of deficient and excess accumulated deferred income tax assets and liabilities that are considered protected and unprotected as of December 31, 2019 and 2018 is reflected below.

(Millions of Dollars)	Dec. 31, 2019		Dec. 31, 2018	
Account	182.3	254	182.3	254
Protected				
Plant	$ —	$ 456.4	$ —	$ 468.9
Nonplant	53.3	—	54.8	—
Unprotected				
Plant	—	65.8	—	69.8
Nonplant	0.3	17.9	1.0	$ (23.0)
Total				
Plant	$ —	$ 522.2	$ —	$ 538.7
Nonplant	$ 53.6	$ 17.9	$ 55.8	$ (23.0)

Excess and deficient accumulated deferred income taxes (ADITs) in 2019 were amortized in the Statement of Income as follows:

(Millions of Dollars)	Dec. 31, 2019
Protected	
Plant	$ (7.3)
Nonplant	0.7
Unprotected	
Plant	(2.2)
Nonplant	(3.4)
Total	
Plant	$ (9.5)
Nonplant	$ (2.7)

5. 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 disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

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

Specific valuation methods include:

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

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.

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are expected to be recovered through fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of SPS.

Derivative Fair Value Measurements

SPS enters into derivative instruments, including forward contracts, for trading purposes and to manage risk in connection with changes in interest rates and electric utility commodity prices.

Interest Rate Derivatives — SPS may enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes. As of Dec. 31, 2019, accumulated other comprehensive losses related to interest rate derivatives included $0.1 million 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 — SPS conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments, including derivatives. SPS is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Commodity Derivatives — SPS enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric utility operations. This could include the purchase or sale of energy or energy-related products and FTRs.

Gross notional amounts of commodity FTRs at Dec. 31, 2019 and 2018:

(Amounts in Millions) (a)	Dec. 31, 2019	Dec. 31, 2018
Megawatt hours of electricity	6.4	5.5

(a) Amounts are not reflective of net positions in the underlying commodities.

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

SPS' 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, 2019, three of the ten most significant counterparties for these activities, comprising $12.2 million or 35% of this credit exposure, had investment grade ratings from Standard & Poor's, Moody's or Fitch Ratings. Six of the ten most significant counterparties, comprising $22.1 million or 65% of this credit exposure, were not rated by external rating agencies, but based on SPS' internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising $0.1 million or less than 1% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Nine of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate cash flow hedges on SPS' accumulated other comprehensive loss, included in the statements of common stockholder's equity and in the statements of comprehensive income:

(Millions of Dollars)	2019	2018
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (0.7)	$ (0.8)
After-tax net realized losses on derivative transactions reclassified into earnings	—	0.1
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (0.7)	$ (0.7)

Pre-tax losses related to interest rate derivatives reclassified from accumulated other comprehensive loss into earnings were immaterial, $0.1 million and $0.1 million for the years ended Dec. 31, 2019 and 2018, respectively.

Changes in the fair value of FTRs resulting in pre-tax net gains of $6.5 million and $7.0 million recognized for the years ended Dec. 31, 2019 and 2018, respectively, were reclassified as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on expected recovery of FTR settlements through fuel and purchased energy cost recovery mechanisms.

FTR settlement gains of $6.0 million and $4.4 million were recognized for the years ended Dec. 31, 2019 and 2018, respectively, and were recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

SPS had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2019 and 2018.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, SPS' derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2019 and 2018:

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting (a)	Total
Current derivative assets												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 11.8	$ 11.8	$ —	$ 11.8	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	$ 14.7
Total current derivative assets	$ —	$ —	$ 11.8	$ 11.8	$ —	11.8	$ —	$ —	$ 14.9	$ 14.9	$ (0.2)	14.7
PPAs (b)						3.2						3.1
Current derivative instruments						$ 15.0						$ 17.8
Noncurrent derivative assets												
PPAs (b)						12.6						15.8
Noncurrent derivative instruments						$ 12.6						$ 15.8
Current derivative liabilities												
Other derivative instruments:												
Electric commodity	$ —	$ —	$ 0.1	$ 0.1	$ —	$ 0.1	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	$ —
Total current derivative liabilities	$ —	$ —	$ 0.1	$ 0.1	$ —	0.1	$ —	$ —	$ 0.2	$ 0.2	$ (0.2)	—
PPAs (b)						3.6						3.6
Current derivative instruments						$ 3.7						$ 3.6
Noncurrent derivative liabilities												
PPAs (b)						12.8						16.4
Noncurrent derivative instruments						$ 12.8						$ 16.4

(a) SPS nets derivative instruments and related collateral in its 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, 2019 and 2018. At both Dec. 31, 2019 and 2018, derivative assets and liabilities include no obligations to return cash collateral or rights to reclaim cash collateral. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, SPS 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.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2019 and 2018:

(Millions of Dollars)	Year Ended Dec. 31 2019	Year Ended Dec. 31 2018
Balance at Jan. 1	$ 14.7	$ 12.7
Purchases	26.7	32.3
Settlements	(34.2)	(41.6)
Net transactions recorded during the period:		
Net gains recognized as regulatory assets	4.5	11.3
Balance at Dec. 31	$ 11.7	$ 14.7

SPS recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2017 – 2019.

Fair Value of Long-Term Debt

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

(Millions of Dollars)	2019 Carrying Amount	2019 Fair Value	2018 Carrying Amount	2018 Fair Value
Long-term debt	$ 2,442.9	$ 2,706.1	$ 2,146.5	$ 2,139.8

Fair value of SPS' long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2019 and 2018, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

6. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2019 and 2018 were $39 million and $33 million, respectively, of which $2 million was attributable to SPS in both years. In 2019 and 2018, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2019 and 2018, of which immaterial amounts were attributable to SPS.

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

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

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- Investment returns in 2019 were above the assumed level of 6.78%;
- Investment returns in 2018 were below the assumed level of 6.78%; and
- In 2020, Xcel Energy's expected investment-return assumption is 6.78%.

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

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

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

Plan Assets

For each of the fair value hierarchy levels, SPS' pension plan assets measured at fair value:

	Dec. 31, 2019 (a)					Dec. 31, 2018 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 18.9	$ —	$ —	$ —	$ 18.9	$ 21.6	$ —	$ —	$ —	$ 21.6
Commingled funds	202.5	—	—	144.8	347.3	128.6	—	—	132.5	261.1
Debt securities	—	98.2	0.6	—	98.8	—	98.1	—	—	98.1
Equity securities	12.1	—	—	—	12.1	14.4	—	—	—	14.4
Other	(16.8)	0.7	—	(2.8)	(18.9)	0.2	0.8	—	(4.0)	(3.0)
Total	$ 216.7	$ 98.9	$ 0.6	$ 142.0	$ 458.2	$ 164.8	$ 98.9	$ —	$ 128.5	$ 392.2

(a) See Note 5 for further information on fair value measurement inputs and methods.

For each of the fair value hierarchy levels, SPS' proportionate allocation of the total postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2019 (a)					Dec. 31, 2018 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 2.2	$ —	$ —	$ —	$ 2.2	$ 1.8	$ —	$ —	$ —	$ 1.8
Insurance contracts	—	4.9	—	—	4.9	—	4.3	—	—	4.3
Commingled funds:	6.7	—	—	7.4	14.1	12.8	—	—	3.8	16.6
Debt securities:	—	22.1	0.1	—	22.2	—	17.2	—	—	17.2
Equity securities:	—	—	—	—	—	—	—	—	—	—
Other	—	0.2	—	—	0.2	—	0.1	—	—	0.1

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Total	$ 8.9	$ 27.2	$ 0.1	$ 7.4	$ 43.6	$ 14.6	$ 21.6	$ —	$ 3.8	$ 40.0

(a) See Note 5 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2019. No assets were transferred in or out of Level 3 for 2018.

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

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 477.8	$ 515.9	$ 41.8	$ 47.0
Service cost	8.8	9.7	0.9	1.1
Interest cost	20.1	18.4	1.7	1.6
Plan amendments	—	—	—	—
Actuarial loss (gain)	44.2	(34.8)	0.4	(5.1)
Plan participants' contributions	—	—	0.6	0.6
Benefit payments (a)	(32.1)	(31.4)	(2.2)	(3.4)
Obligation at Dec. 31	$ 518.8	$ 477.8	$ 43.2	$ 41.8
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 392.2	$ 433.2	$ 40.0	$ 44.1
Actual return on plan assets	80.2	(17.6)	5.1	(1.3)
Employer contributions	17.9	8.0	0.1	—
Plan participants' contributions	—	—	0.6	0.6
Benefit payments	(32.1)	(31.4)	(2.2)	(3.4)
Fair value of plan assets at Dec. 31	$ 458.2	$ 392.2	$ 43.6	$ 40.0
Funded status of plans at Dec. 31	$ (60.6)	$ (85.6)	$ 0.4	$ (1.8)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent assets	—	—	0.4	—
Noncurrent liabilities	(60.6)	(85.6)	—	(1.8)
Net amounts recognized	$ (60.6)	$ (85.6)	$ 0.4	$ (1.8)
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	3.49%	4.31%	3.47%	4.32%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	Pri-2012	RP-2014	Pri-2012	RP-2014
Health care costs trend rate — initial: Pre-Medicare	N/A	N/A	6.00%	6.50%
Health care costs trend rate — initial: Post-Medicare	N/A	N/A	5.10%	5.30%
Ultimate trend assumption — initial: Pre-Medicare	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-Medicare	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	3	4

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(a) Includes approximately $6.8 million in 2019 and $6.9 million in 2018, of lump-sum benefit payments used in the determination of a settlement charge.

Accumulated benefit obligation for the pension plan was $481.1 million and $445.8 million as of Dec. 31, 2019 and 2018, respectively.

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

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

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Service cost	$ 8.8	$ 9.7	$ 0.9	$ 1.1
Interest cost	20.1	18.4	1.7	1.6
Expected return on plan assets	(28.6)	(28.3)	(2.0)	(2.5)
Amortization of prior service credit	(0.1)	(0.1)	(0.5)	(0.4)
Amortization of net loss	11.3	14.1	(0.4)	(0.4)
Settlement charge (a)	2.4	3.2	—	—
Net periodic pension cost (credit)	13.9	17.0	(0.3)	(0.6)
Costs not recognized due to effects of regulation	0.9	(2.2)	—	—
Net benefit cost (credit) recognized for financial reporting	$ 14.8	$ 14.8	$ (0.3)	$ (0.6)
Significant Assumptions Used to Measure Costs:				
Discount rate	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	6.78	6.78	5.30	5.80

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2019 and 2018, as a result of lump-sum distributions during the 2019 and 2018 plan years, SPS recorded a total pension settlement charge of $2.4 million and $3.2 million in 2019 and 2018, respectively. A total of $0.6 million and $0.7 million of that amount was recorded in the income statement in 2019 and 2018, respectively.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 209.7	$ 230.9	$ (11.9)	$ (9.6)
Prior service credit	(1.1)	(1.2)	(1.4)	(1.8)
Total	$ 208.6	$ 229.7	$ (13.3)	$ (11.4)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Noncurrent deferred debits	$ 208.6	$ 229.7	$ —	$ —
Noncurrent deferred credits	—	—	(13.3)	(11.4)
Total	$ 208.6	$ 229.7	$ (13.3)	$ (11.4)

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Measurement date	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018

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 2017 - 2020 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 2020, of which $14 million was attributable to SPS;
- $154 million in 2019, of which $18 million was attributable to SPS; and
- $150 million in 2018, of which $8 million was attributable to SPS.

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

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. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy's voluntary postretirement funding contributions were as follows:

- Expects to contribute approximately $10 million during 2020;
- $15 million during 2019;
- $11 million during 2018; and
- Amounts attributable to SPS were immaterial.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2019	2018	2019	2018
Domestic and international equity securities	37%	35%	15%	18%
Long-duration fixed income securities	30	32	—	—
Short-to-intermediate fixed income securities	14	16	72	70
Alternative investments	17	15	9	8
Cash	2	2	4	4
Total	100%	100%	100%	100%

Plan Amendments — Xcel Energy, which includes SPS, 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 2019 and 2018, there were no plan amendments made which affected the benefit obligation.

Projected Benefit Payments

SPS' projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2020	$ 30.7	$ 2.9	$ —	$ 2.9
2021	29.4	2.9	—	2.9
2022	30.3	2.9	—	2.9
2023	30.4	2.9	—	2.9
2024	30.4	2.8	—	2.8
2025-2029	153.5	13.2	0.1	13.1

Defined Contribution Plans

Xcel Energy, which includes SPS, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for SPS was approximately $3 million in 2019 and 2018.

7. Commitments and Contingencies

Legal

SPS 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 complex judgments about future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation.

Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on SPS' financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

Texas Fuel Reconciliation — In December 2018, SPS filed an application with the Public Utilities Commission of Texas (PUCT) for reconciliation of fuel costs for the period Jan. 1, 2016, through June 30, 2018, to determine whether all fuel costs incurred were eligible for recovery. In December 2019, the PUCT issued an order disallowing recovery of costs for Texas customers related to two specific solar PPAs. These PPAs were previously approved by the NMPRC as reasonable, necessary and economic. SPS recorded a total disallowance of approximately $6 million in December 2019.

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

In July 2018, SPS' appeal to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for rehearing. Timing of a FERC response to rehearing requests is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. Timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

SPP Filing to Assign GridLiance Facilities to SPS Rate Zone — In August 2018, SPP filed a request with the FERC to amend its OATT to include costs of the GridLiance High Plains, LLC. facilities in the SPS rate zone. In a previous filing, the FERC determined that some of these facilities did not qualify as transmission facilities under the SPP OATT.

In September 2018, SPS protested the proposed SPP tariff charges, and asked the FERC to reject the SPP filing. On Oct. 31, 2018, the FERC issued an order accepting the proposed charges, subject to refund, as of Nov. 1, 2018, and set the case for settlement hearing procedures. Hearings are scheduled for May 2020, with the ALJs' initial decision expected in October 2020. SPS has incurred approximately $6 million in associated charges as of Dec. 31, 2019.

SPS Filing to Modify Wholesale Transmission Rates — In 2018, SPS filed revisions to its wholesale transmission formula rate. The proposal includes an update to depreciation rates for transmission plant. The new formula rate would also provide a credit to customers of "excess" ADIT resulting from the TCJA and recover certain wholesale regulatory commission expenses.

Proposed changes would increase wholesale transmission revenues by approximately $9.4 million, with approximately $4.4 million of the total recovered in SPP regional transmission rates. SPS proposed formula rate changes be effective Feb. 1, 2019.

In January 2019, the FERC issued an order accepting the proposed rate changes as of Feb. 1, 2019, subject to refund and settlement procedures. On Dec. 23, 2019, SPS filed a Stipulation and Agreement of Settlement. If approved by the FERC, the settlement would implement the requested depreciation and TCJA related changes, but would not modify current treatment of wholesale regulatory commission expenses.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for SPS, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. SPS may sometimes pay all or a portion of the cost to remediate sites where past activities of SPS' predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs); and third-party sites, such as landfills, for which SPS is alleged to have sent wastes to that site.

MGP, Landfill or Disposal Sites — SPS is currently remediating the site of a former facility. SPS has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Federal Clean Water Act (CWA) Waters of the U.S. (WOTUS) Rule — In 2015, the United States Environmental Protection Agency (EPA) and Corps published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". In 2019, the EPA repealed the 2015 rule and published a draft replacement rule. Until a final rule is issued, SPS cannot estimate potential impacts, but anticipates costs will be recoverable through regulatory mechanisms.

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Federal CWA Effluent Limitation Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals (CCRs). In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, SPS estimates that ELG compliance costs will be immaterial. The EPA, however, is conducting a rulemaking process to revise certain effluent limitations and pretreatment standards, which may impact compliance costs. SPS anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires sulfur dioxide (SO_2), nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. Texas' first regional haze plan has undergone federal review as described below.

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

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

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking, which was supplemented by an additional agency notice in November 2019. It is not known when the EPA will make a final decision on this proposal.

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

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

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

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

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AROs — AROs have been recorded for SPS' assets.

SPS' AROs were as follows:

	2019					
(Millions of Dollars)	**Jan. 1, 2019**	**Amounts Incurred** (a)	**Amounts Settled** (b)	**Accretion**	**Cash Flow Revisions** (c)	**Dec. 31, 2019**
Electric						
Steam and other production	$ 22.0	$ —	$ (1.6)	$ 1.4	$ 29.5	$ 51.3
Wind	—	16.0	—	0.4	—	16.4
Distribution	9.1	—	—	0.4	—	9.5
Common	1.3	—	—	—	(1.2)	0.1
Total liability	$ 32.4	$ 16.0	$ (1.6)	$ 2.2	$ 28.3	$ 77.3

(a) Amounts incurred related to the Hale wind farm placed in service in 2019.

(b) Amounts settled related to asbestos abatement projects.

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Changes in steam production AROs primarily related to the cost estimates to remediate ponds at production facilities.

	2018			
(Millions of Dollars)	**Jan. 1, 2018**	**Accretion**	**Cash Flow Revisions** (a)	**Dec. 31, 2018** (b)
Electric				
Steam and other production	$ 20.3	$ 1.2	$ 0.5	$ 22.0
Distribution	7.0	0.3	1.8	9.1
Common	1.2	0.1	—	1.3
Total liability	$ 28.5	$ 1.6	$ 2.3	$ 32.4

(a) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in electric distribution AROs were primarily related to increased labor costs.

(b) There were no ARO amounts incurred or settled in 2018.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of SPS' facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2019. Therefore, an ARO has not been recorded for these facilities.

Leases

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SPS evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under the Financial Accounting Standards Board Accounting Standards Codification Topic 842, adopted by SPS on Jan. 1, 2019, a contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent SPS' rights to use leased assets. In accordance with FERC requirements as provided in Docket No. AI19-1-000, starting in 2019, the present value of future operating lease payments are recognized in Account 227 and Account 243. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets in Account 101.1.

Most of SPS' leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is calculated using the estimated incremental borrowing rate (weighted-average of 4.4%). SPS has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure. Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets in Account 101.1:

(Millions of Dollars)	Dec. 31, 2019
PPAs	$ 500.3
Other	48.0
Gross operating lease ROU assets	548.3
Accumulated amortization	(25.9)
Net operating lease ROU assets	$ 522.4

Components of lease expense:

(Millions of Dollars)	2019	2018
Operating leases		
PPA capacity payments	$ 48.1	$ 51.1
Other operating leases (a)	4.9	7.9
Total operating lease expense (b)	$ 53.0	$ 59.0

(a) Includes short-term lease expense of $1.5 million, $1.1 million for 2019 and 2018, respectively.

(b) PPA capacity payments and expense for other operating leases are included in electric fuel and purchased power on the statements of income.

Future commitments under operating leases as of Dec. 31, 2019 in Accounts 227 and 243:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases
2020	$ 46.2	$ 3.4	$ 49.6
2021	46.2	3.3	49.5
2022	46.2	3.4	49.6
2023	46.2	3.4	49.6
2024	46.2	3.5	49.7
Thereafter	404.5	51.3	455.8
Total minimum obligation	635.5	68.3	703.8
Interest component of obligation	(160.0)	(21.6)	(181.6)

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Present value of minimum obligation	475.5	46.7	522.2
Less current portion			(26.9)
Noncurrent operating lease liabilities			$ 495.3
Weighted-average remaining lease term in years			14.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

Future commitments under operating leases as of Dec. 31, 2018:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 46.7	$ 5.2	$ 51.9
2020	46.2	5.2	51.4
2021	46.2	5.1	51.3
2022	46.2	5.1	51.3
2023	46.2	5.1	51.3
Thereafter	450.8	56.3	507.1

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

PPAs and Fuel Contracts

Non-Lease PPAs — SPS has entered into PPAs with other utilities and energy suppliers with various expiration dates through 2024 for purchased power to meet system load and energy requirements and operating reserve obligations.

In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Capacity payments are contingent on the IPP meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts, were payments for capacity of $19.9 million, $57.6 million and $58.4 million in 2019, 2018 and 2017, respectively.

At Dec. 31, 2019, the estimated future payments for capacity that SPS is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity
2020	$ 12.3
2021	12.5
2022	12.7
2023	13.0
2024	5.9
Thereafter	—
Total	$ 56.4

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Fuel Contracts — SPS has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal and natural gas requirements. These contracts expire between 2020 and 2033. SPS is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2019:

(Millions of Dollars)	Coal	Natural gas supply	Natural gas storage and transportation
2020	$ 96.7	$ 12.3	$ 28.9
2021	67.7	—	23.3
2022	38.8	—	17.4
2023	—	—	12.7
2024	—	—	6.7
Thereafter	—	—	26.3
Total	$ 203.2	$ 12.3	$ 115.3

8. Other Comprehensive Income

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

	2019		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (0.7)	$ (0.7)	$ (1.4)
Other comprehensive loss before reclassifications (net of taxes of $0 and $(0.1), respectfully	—	(0.2)	(0.2)
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of net actuarial loss (net of taxes of $0)	—	0.2 (a)	0.2
Net current period other comprehensive income (loss)	—	—	—
Accumulated other comprehensive loss at Dec. 31	$ (0.7)	$ (0.7)	$ (1.4)

(a) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for further information.

	2018		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (0.8)	$ (0.7)	$ (1.5)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $0)	0.1 (a)	—	0.1
Net current period other comprehensive income	0.1	—	0.1
Accumulated other comprehensive loss at Dec. 31	$ (0.7)	$ (0.7)	$ (1.4)

(a) Included in interest charges.

9. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including SPS. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. SPS uses the service 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 with the utility subsidiaries.

See Note 3 for further information.

Significant affiliate transactions among the companies and related parties for the years ended Dec. 31:

(Millions of Dollars)	2019	2018
Operating expenses:		
Other operating expenses — paid to Xcel Energy Services Inc.	$ 192.0	$ 195.1
Interest expense	0.2	0.6

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

	2019		2018	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 4.2	$ —	$ 4.7	$ —
PSCo	—	0.4	—	0.7
Other subsidiaries of Xcel Energy Inc.	—	20.0	5.8	19.2
	$ 4.2	$ 20.4	$ 10.5	$ 19.9

10. Supplementary Cash Flow Data

(Millions of Dollars)	2019	2018
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (83.6)	$ (71.2)
Cash received (paid) for income taxes, net	11.9	(10.6)
Supplemental disclosure of non-cash investing transactions:		
Utility plant additions in accounts payable	$ 94.5	$ 71.5
Inventory transfer additions in utility plant	23.3	22.5
Operating lease right-of-use assets	548.3	—
Allowance for equity funds used during construction	26.8	19.1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(691,263)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				74,606
3	Preceding Quarter/Year to Date Changes in Fair Value				(47,797)
4	Total (lines 2 and 3)				26,809
5	Balance of Account 219 at End of Preceding Quarter/Year				(664,454)
6	Balance of Account 219 at Beginning of Current Year				(664,454)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				161,675
8	Current Quarter/Year to Date Changes in Fair Value				(232,876)
9	Total (lines 7 and 8)				(71,201)
10	Balance of Account 219 at End of Current Quarter/Year				(735,655)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(775,205)		(1,466,468)	[redacted]	
2	49,244		123,850		
3			(47,797)		
4	49,244		76,053	213,320,225	213,396,278
5	(725,961)		(1,390,415)	[redacted]	
6	(725,961)		(1,390,415)		
7	49,180		210,855		
8			(232,876)		
9	49,180		(22,021)	263,067,322	263,045,301
10	(676,781)		(1,412,436)	[redacted]	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	7,010,586,762	7,010,586,762
4	Property Under Capital Leases	522,437,456	475,719,564
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,436,968,472	1,436,968,472
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,969,992,690	8,923,274,798
9	Leased to Others		
10	Held for Future Use	4,167,109	4,167,109
11	Construction Work in Progress	486,406,071	486,406,071
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,460,565,870	9,413,847,978
14	Accum Prov for Depr, Amort, & Depl	2,480,929,856	2,480,929,856
15	Net Utility Plant (13 less 14)	6,979,636,014	6,932,918,122
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,324,975,102	2,324,975,102
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	155,954,754	155,954,754
22	Total In Service (18 thru 21)	2,480,929,856	2,480,929,856
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,480,929,856	2,480,929,856

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
				46,717,892	4
					5
					6
					7
				46,717,892	8
					9
					10
					11
					12
				46,717,892	13
					14
				46,717,892	15
					16
					17
					18
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					33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 8 Column: c

Page 204, Line 104, column g	$8,447,555,235
Plus Operating Right of Use Asset	$ 475,719,563
Page 200, Line 8, column c	$8,923,274,798

Schedule Page: 200 Line No.: 21 Column: c

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	$125,396,036
Transmission	23,220,150
Steam Production	4,557,433
Distribution	1,619,006
General	1,161,447
Other Production	682
Total	$155,954,754

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
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			11
			12
			13
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			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	215,877,631	18,511,875
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	215,877,631	18,511,875
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	17,078,045	
9	(311) Structures and Improvements	240,705,239	4,043,921
10	(312) Boiler Plant Equipment	1,002,571,316	21,061,831
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	508,525,087	17,340,438
13	(315) Accessory Electric Equipment	83,874,612	3,233,457
14	(316) Misc. Power Plant Equipment	32,063,906	970,622
15	(317) Asset Retirement Costs for Steam Production	-254,076	28,300,863
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,884,564,129	74,951,132
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	207,293	-36,542
38	(341) Structures and Improvements	14,401,896	45,733,752
39	(342) Fuel Holders, Products, and Accessories	6,071,842	29,154
40	(343) Prime Movers	54,837,615	
41	(344) Generators	177,441,997	621,597,498
42	(345) Accessory Electric Equipment	31,715,809	19,794,344
43	(346) Misc. Power Plant Equipment	4,745,530	35,201
44	(347) Asset Retirement Costs for Other Production	136,263	16,016,581
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	289,558,245	703,169,988
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,174,122,374	778,121,120

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	160,593,830	5,531,726
49	(352) Structures and Improvements	101,632,640	21,174,404
50	(353) Station Equipment	1,108,171,070	116,241,168
51	(354) Towers and Fixtures	8,177,681	30,988
52	(355) Poles and Fixtures	1,160,752,858	125,004,678
53	(356) Overhead Conductors and Devices	446,002,531	31,207,121
54	(357) Underground Conduit	272,859	2,145
55	(358) Underground Conductors and Devices	489,716	
56	(359) Roads and Trails	517,736	
57	(359.1) Asset Retirement Costs for Transmission Plant	25,029	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,986,635,950	299,192,230
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	14,899,742	5,328,882
61	(361) Structures and Improvements	26,694,693	3,292,108
62	(362) Station Equipment	286,799,166	23,262,345
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	296,896,083	39,692,247
65	(365) Overhead Conductors and Devices	271,310,371	17,108,023
66	(366) Underground Conduit	25,325,347	1,189,410
67	(367) Underground Conductors and Devices	45,079,211	3,545,329
68	(368) Line Transformers	218,336,064	11,488,337
69	(369) Services	89,049,550	4,549,977
70	(370) Meters	67,144,514	3,712,493
71	(371) Installations on Customer Premises	1,509	371
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	30,552,349	4,473,494
74	(374) Asset Retirement Costs for Distribution Plant	7,467,368	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,379,555,967	117,643,016
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,103,209	
87	(390) Structures and Improvements	72,961,255	7,712,432
88	(391) Office Furniture and Equipment	85,495,596	27,807,666
89	(392) Transportation Equipment	112,573,762	4,807,432
90	(393) Stores Equipment	430,682	
91	(394) Tools, Shop and Garage Equipment	43,989,343	4,905,695
92	(395) Laboratory Equipment	11,180,733	
93	(396) Power Operated Equipment	14,816,243	
94	(397) Communication Equipment	118,455,184	6,731,570
95	(398) Miscellaneous Equipment	2,781,557	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	463,787,564	51,964,795
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	64,395	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	463,851,959	51,964,795
100	TOTAL (Accounts 101 and 106)	7,220,043,881	1,265,433,036
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	7,220,043,881	1,265,433,036

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
4,189,937			230,199,569		4
4,189,937			230,199,569		5
					6
					7
			17,078,045		8
63,250			244,685,910		9
1,157,295			1,022,475,852		10
					11
1,789,242			524,076,283		12
60,319			87,047,750		13
95,529			32,938,999		14
			28,046,787		15
3,165,635			1,956,349,626		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
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					31
					32
					33
					34
					35
					36
			170,751		37
			60,135,648		38
			6,100,996		39
			54,837,615		40
46,525			798,992,970		41
			51,510,153		42
9,744			4,770,987		43
			16,152,844		44
56,269			992,671,964		45
3,221,904			2,949,021,590		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			166,125,556		48
302,935		-1,988,378	120,515,731		49
9,941,453		2,000,053	1,216,470,838		50
			8,208,669		51
2,765,445			1,282,992,091		52
1,435,450			475,774,202		53
			275,004		54
			489,716		55
			517,736		56
			25,029		57
14,445,283		11,675	3,271,394,572		58
					59
			20,228,624		60
211,128			29,775,673		61
3,346,433		-152,072	306,563,006		62
					63
2,627,105			333,961,225		64
3,842,992			284,575,402		65
3,173			26,511,584		66
120,455			48,504,085		67
1,724,467			228,099,934		68
143,008			93,456,519		69
2,334,291			68,522,716		70
-10,022,908		3,020,795	13,045,583		71
					72
1,829,698		-3,020,795	30,175,350		73
			7,467,368		74
6,159,842		-152,072	1,490,887,069		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,103,209		86
409,057			80,264,630		87
8,306,217			104,997,045		88
-21			117,381,215		89
-242			430,924		90
130,141			48,764,897		91
242,223			10,938,510		92
822,504			13,993,739		93
		140,397	125,327,151		94
-5,163			2,786,720		95
9,904,716		140,397	505,988,040		96
					97
			64,395		98
9,904,716		140,397	506,052,435		99
37,921,682			8,447,555,235		100
					101
					102
					103
37,921,682			8,447,555,235		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 58 Column: b

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	-	63,075	-	-	-	63,075
Account 352 - Structures & Improvements	723,970	1,256,620	-	-	-	1,980,590
Account 353 - Station Equipment	29,483,652	13,548,260	(284,946)	-	-	42,746,966
Account 355 - Poles & Fixtures	260,474	8,367,254	-	-	-	8,627,728
Account 356 - Overhead Conductors & Devices	24,718	4,760,706	-	-	-	4,785,424

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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30					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Electric Prod Other-TX-Gaines County	2015	2024+	4,167,109
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			4,167,109

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SPS Wind - Sagamore	241,180,363
2	TUCO-Yoakum 345kV Line_UID 504	103,805,366
3	Kiowa-Eddy Co 345kV Line	12,286,898
4	ADMS SW SPS	9,085,549
5	Plant X Add BFR on All 115 kV	7,316,644
6	Amarillo Ops Center Renovation	5,312,874
7	Plant X Rpl Brkr Switch WT Sub	5,283,553
8	TOL2C-Prch & Install New GSU XFMR	3,804,085
9	ITC - Purch ITINFS Valkyrie HW SPS	3,634,101
10	W77 Canyon East Tap to Arrowhe	3,187,409
11	TOL1C-Synchronous Condenser	3,142,584
12	TOL2C-Synchronous Condenser	2,678,358
13	SPS Transmission UAV	2,651,078
14	TUCO 345kV Sub Reactor/Y Term_	2,565,713
15	Plant X 115kV Switch Replacement	2,546,500
16	CIP Substation Ph2 SW SPS -10659	2,361,497
17	Yoakum 345kV Sub Reactor/TUCO	2,299,378
18	SPS Landworks - Convert docs to dig	2,273,496
19	Artesia Country Club TAM Conve	1,981,196
20	OPIE 3 W 39 Rbld PHTM RDBF	1,756,187
21	NIC0C-HW Rd. WW Trtment Improv	1,610,879
22	TUCO SPE relay Upgrades TX	1,546,559
23	PLX3C Rpl East Waterwall Tubes	1,520,666
24	JAL EO/Sage Brush 4520 / RoadRunner	1,408,982
25	DEMS Ph4 HW SPS-10756	1,348,782
26	Net Auto Platform SW SPS-10741	1,305,269
27	20180517_PEARL_4D25	1,282,614
28	Carlsbad 115kV Switch Replacement	1,195,414
29	Amherst Tap Rebuild Line	1,144,888
30	Mustang - Seminole New 115kV Line	1,140,675
31	Littlefield West Tap Rebuild Line	1,113,895
32	ITC-Purch WAN Generator TX	1,071,246
33	Minor Projects	51,563,373
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	486,406,071

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,183,663,453	2,183,663,453		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	196,451,788	196,451,788		
4	(403.1) Depreciation Expense for Asset Retirement Costs	619,059	619,059		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	8,444,060	8,444,060		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	205,514,907	205,514,907		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	33,731,743	33,731,743		
13	Cost of Removal	35,604,197	35,604,197		
14	Salvage (Credit)	3,696,145	3,696,145		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	65,639,795	65,639,795		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,436,537	1,436,537		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,324,975,102	2,324,975,102		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,159,106,813	1,159,106,813		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	111,074,693	111,074,693		
25	Transmission	458,706,745	458,706,745		
26	Distribution	379,959,251	379,959,251		
27	Regional Transmission and Market Operation				
28	General	216,127,600	216,127,600		
29	TOTAL (Enter Total of lines 20 thru 28)	2,324,975,102	2,324,975,102		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: c

Net change in RWIP	$	1,107,650
Net Transfers		267,555
(Gain)/Loss		61,254
Other		78
Total	$	1,436,537

Schedule Page: 219 Line No.: 25 Column: c

Transmission Serving Production	$	16,292,631

Schedule Page: 219 Line No.: 29 Column: b

	"Non-Legal" ARO Balances
Steam Production	$ 103,481,207
Other Production	3,172,838
Transmission	12,876,099
Distribution	53,436,439
General	1,551,783
Total	$ 174,518,366

Schedule Page: 219 Line No.: 29 Column: c

NOTE: Amounts footnoted are based upon FERC ONLY RATES and EXCLUDES ASSET RETIREMENT COSTS (ARC).

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)
1	Balance Beginning of Year	$ 2,322,830,557	$ 2,322,830,557
2	Depreciation Provisions for Year, Charged to		
3	(403) Depreciation Expense	190,871,206	190,871,206
4	(403.1) Depreciation Expense for Asset Retirement Costs	-	-
5	(413) Exp of Elec Plt. Leas. To Others	-	-
6	Transportation Expenses-Clearing	7,827,569	7,827,569
7	Other Clearing Accounts	-	-
8	Other Accounts (Specify, details in footnote):	-	-
9			
10	Total Deprec. Prov for year (Enter Total of lines 3 thru 9)	198,698,775	198,698,775
11	Net Charges for Plant Retired		
12	Book Cost of Plant Retired	33,731,743	33,731,743
13	Cost of Removal	35,604,197	35,604,197
14	Salvage (Credit)	3,696,145	3,696,145
15	Total Net Chrgs for Plant Ret. (Enter Total of lines 12 thru 14)	65,639,795	65,639,795
16	Other Debit or Cr. Items (Describe, details in footnote):	35,932,542	35,932,542
17			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

18	Book Cost or Asset Retirement Costs Retired	-	-
19	Balance End of Year (Enter Totals of lines 1,10,15,16 and 18)	$ 2,491,822,079	$ 2,491,822,079
Section B. Balances at End of Year According to Functional Classification			
20	Steam Production	$ 1,383,464,953	$ 1,383,464,953
21	Nuclear Production	-	-
22	Hydraulic Production-Conventional	-	-
23	Hydraulic Production-Pumped Storage	-	-
24	Other Production	124,461,536	124,461,536
25	Transmission	377,035,266	377,035,266
26	Distribution	378,376,022	378,376,022
27	Regional Transmission and Market Operation	-	-
28	General	228,484,302	228,484,302
29	Total (Enter Total of lines 20 thru 28)	$ 2,491,822,079	$ 2,491,822,079

Net change in RWIP	$ 1,107,650
Net Transfers and Adjustments	34,763,562
Gain/Loss	61,254
Other	76
Total	$ 35,932,542

*Total agrees to line 16 in the schdedule above.

Transmission Serving Production Reserve	$ 19,362,745

*Footnote to line 25 in the schdedule above.

	"Non-Legal" ARO Balances
Steam Production	$ 221,028,379
Other Production	4,007,564
Transmission	(102,725,044)
Distribution	53,436,439
General	2,798,148
Total	$ 178,545,486

*Footnote to lines 20-28 in the schdedule above.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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32				
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34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
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				41
				42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	8,202,732	6,314,902	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	10,473,965	9,765,565	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	9,982,557	10,795,265	Electric
8	Transmission Plant (Estimated)	121,150	113,797	Electric
9	Distribution Plant (Estimated)	360,782	217,123	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-127,883	-93,010	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	20,810,571	20,798,740	
13	Merchandise (Account 155)	188,238	153,261	
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	29,201,541	27,266,903	

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FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

Balance is comprised of miscellaneous inventory-related items (including purchase price variances, obsolescence and suspense items).

Schedule Page: 227 Line No.: 11 Column: c

Balance is comprised of miscellaneous inventory-related items (including purchase price variances, obsolescence and suspense items).

Balance includes chemical inventory (ARKAY). Beginning balance of chemical inventory as of January 1 was $85,067 and ending balance as of December 31, 2019 is $102,219.

Balance includes chemical inventory (Mercury Sorbent). Beginning balance of chemical inventory as of January 1 was $63,786 and ending balance as of December 31, 2019 is $97,845.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	264,329.00		53,364.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	29,633.00		29,633.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	35,425.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	258,537.00		82,997.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	771.00		771.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	771.00			
40	Balance-End of Year			771.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	771.00	9		
45	Gains		9		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
53,364.00		53,364.00		1,440,828.00		1,865,249.00		1
								2
								3
29,633.00		29,633.00		53,364.00		171,896.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						35,425.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
82,997.00		82,997.00		1,494,192.00		2,001,720.00		29
								30
								31
								32
								33
								34
								35
771.00		771.00		20,817.00		23,901.00		36
				1,542.00		1,542.00		37
								38
				771.00		1,542.00		39
771.00		771.00		21,588.00		23,901.00		40
								41
								42
								43
				771.00	2	1,542.00	11	44
					2		11	45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 228 Line No.: 1 Column: b

The amounts recorded in FERC account 158.1 on page 110 represent the Texas portion of Renewable Energy Credits and do not relate to EPA issued allowances.

2018 and prior SO2 bank (ARP & CSAPR)	181,332
2018 ARP	53,364
2019 Federal Texas Only SO2 Program	29,633
	264,329

Schedule Page: 228 Line No.: 1 Column: d

2020 Annual ARP allowances	53,364

Schedule Page: 228 Line No.: 1 Column: f

2021 Annual ARP allowances	53,364

Schedule Page: 228 Line No.: 1 Column: h

2022 Annual ARP allowances	53,364

Schedule Page: 228 Line No.: 1 Column: j

Sum of all ARP Allowances years 2023 and forward to 2048	1,440,828

Schedule Page: 228 Line No.: 4 Column: j

This is the allocations added this year for 2049	53,364

Schedule Page: 228 Line No.: 18 Column: b

ARP charges (includes NM units)	17,724
CSAPR charges (Texas removed from CSAPR SO2 program)	0
Federal Texas Only Program charges	17,701
	35,425

Schedule Page: 228 Line No.: 45 Column: m

Gain-Disposition of SO2 Allowances	$59
SO2 Texas Retail Sharing	(32)
SO2 New Mexico Retail Sharing	(16)
	$11

Value of SO2 allowance inventory is $0.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	7,203.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	59.00		4,044.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	4,092.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	3,170.00		4,044.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						7,203.00		1
								2
								3
4,044.00		4,012.00				12,159.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,092.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
4,044.00		4,012.00				15,270.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 229 Line No.: 1 Column: b

The amounts recorded in FERC account 158.1 on page 110 represent the Texas portion of Renewable Energy Credits and do not relate to EPA issued allowances.

2018 and prior bank (CSAPR & CSAPR Ozone)	3,159
Original Allocation for 2019 (CSAPR Ozone NOx)	4,044
Total	7,203

Schedule Page: 229 Line No.: 4 Column: b

Excess NUSA 2018 Seasonal NOx allowances	59
	59

Schedule Page: 229 Line No.: 4 Column: d

CSAPR Ozone Nox Group 2 2020 vintage	4,044

Schedule Page: 229 Line No.: 4 Column: f

CSAPR Ozone Nox Group 2 2021 vintage	4,044

Schedule Page: 229 Line No.: 4 Column: h

CSAPR Ozone Nox Group 2 2022 vintage	4,012

Schedule Page: 229 Line No.: 18 Column: b

Seasonal Nox emissions for 2019	4,092
	4,092

Schedule Page: 229 Line No.: 29 Column: b

CSAPR Annual Allowances Banked	2,724
2019 & Prior Vintage Ozone NOx Allowances Banked	446
	3,170

Schedule Page: 229 Line No.: 29 Column: c

Value of NOx allowance inventory per books is $0.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	DPA-2018-Jan-854 Lea Co KinderMo	5,284	561.6	5,284	561.6
3	DPA-2018-Jan-854 Lea Co KinderMo			(5,096)	242.0
4	Trans IC DP-RBEC-Kemp			12,500	242.0
5	SISA for SPEC Milwaukee-Yuma			9,549	242.0
6	TCEC/SCMCM Cole Mode Study AQ-863			10,268	242.0
7	Oxy Permian Sub LI_SPP DPA-869			(869)	242.0
8	SPEC - Carlisle Tap NDP	2,351	561.6	2,351	561.6
9	SPEC - Carlisle Tap NDP			9,368	242.0
10	LPL DPA-2018-May-897			(3,039)	242.0
11	RBEC E-Plan, DPA-2019-Sept-1108	1,946	561.6	1,946	561.6
12	RBEC E-Plan, DPA-2019-Sept-1108			(1,946)	242.0
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Pension and Employee Benefit Obligations	230,026,986	393,348	Various	20,965,212	209,455,122
2						
3	Pension and Employee Benefit Cap	1,990,503	1,212,325	926	2,070,617	1,132,211
4	- Texas PUC Docket # 47527					
5						
6	AFUDC in Plant	27,882,557	6,179,833			34,062,390
7	- Amortized over plant life					
8						
9	Non-Nuclear Asset Retirement Obligations	25,733,685	2,756,564	254	1,584,196	26,906,053
10						
11	Prior Flow Thru and Excess ADIT	107,887		254	39,136	68,751
12						
13	Texas Restructuring Meter	122,145		407.3	34,899	87,246
14	- A portion recovered in rates over 20 years					
15	Texas PUC Docket # 25088					
16						
17	Texas Power Demand Factor	286,418	36,327	456	322,745	
18	Docket # 48498 Amortization April 2018- March 2019					
19						
20	Transmission Formula - Attachment O True-Up	3,886,505	3,301,462	Various	2,720,267	4,467,700
21						
22	New Mexico NOx and SO2 Expense	34,908				34,908
23						
24	DSM New Mexico Concurrent	83,845	11,971,222	Various	12,055,067	
25	Case #18-00139-UT					
26						
27	New Mexico RPS Rider		67,288	Various	33,302	33,986
28	Various Amortizations					
29	Case #18-00201-UT					
30						
31	Power Purchased Contract Valuation Adjustments	994,857		244	405,776	589,081
32	- Amortized over life of the contracts					
33						
34	DSM Texas Energy Efficiency		5,950,550	Various	5,343,517	607,033
35	Docket #48324					
36						
37	Non-Plant ADIT	55,842,320	505,404	283	2,775,836	53,571,888
38						
39	2017 TCRF Revenue Accrual	5,346,815		407.4	5,346,815	
40	Docket #47527					
41						
42	Texas Z2 Transmission	5,315,156		407.3	1,309,429	4,005,727
43	Docket #47527					
44	TOTAL	360,121,131	32,374,323		55,527,304	336,968,150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	5 Year Amortization					
2						
3	New Mexico Z2 Transmission	2,466,544		407.3	520,490	1,946,054
4	Case #17-00255-UT					
5	5 Year Amortization					
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
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28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	360,121,131	32,374,323		55,527,304	336,968,150

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 1 Column: e

Accounts charged:

184	$(11,249,356)
926	(2,374,000)
228.3	(7,341,856)
	$(20,965,212)

Schedule Page: 232 Line No.: 1 Column: f

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans -- In September 2006, the FASB issued accounting guidance which requires companies to fully recognize the funded status of each pension and other postretirement benefit plan as a liability or asset on their balance sheets with all unrecognized amounts to be recorded in other comprehensive income. Xcel Energy applied regulatory accounting treatment, which allowed recognition of this item as a regulatory asset rather than as a charge to accumulated other comprehensive income.

Amounts have been recorded as follow based upon expected recovery in Rates:

Regulatory asset - Pension	$208,761,253
Regulatory asset - Non-qualified pension	693,868
	$209,455,121

Schedule Page: 232 Line No.: 20 Column: e

Accounts charged:

565	$ (1,007,401)
456.1	(1,712,866)
	$ (2,720,267)

Schedule Page: 232 Line No.: 24 Column: e

Accounts charged:

908	$(11,230,865)
456	(824,202)
	$(12,055,067)

Schedule Page: 232 Line No.: 27 Column: e

Accounts charged:

421	$ (1,797)
557	(31,505)
	$ (33,302)

Schedule Page: 232 Line No.: 34 Column: e

Accounts charged:

908	$ (4,900,095)
456	(443,422)
	$ (5,343,517)

Schedule Page: 232 Line No.: 37 Column: f

	Nonplant Excess ADIT - Regulatory Asset*	**Gross-Up**	**Reserves (Net of Gross-Up)**	**Total**
Electric	$ 43,530,244	$12,394,271	$ (2,352,627)	$53,571,888
Total	$ 43,530,244	$12,394,271	$ (2,352,627)	$53,571,888

*Total nonplant excess ADIT is $43,530,244. This amount would be included as an increase

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

to rate base for purposes of calculating SPS formula rates, as applicable.

The Nonplant Excess Accumulated Deferred Income Taxes above include the following ungrossed amounts:

Bad Debts	270,153
Demand Side Management	134,978
Deferred Compensation Plan Reserve	32,326
Employee Incentive	395,566
Environmental Remediation	9,265
Federal Net Operating Loss Benefit	42,698,354
Fuel Tax Credit - Income Addback	795
Inventory Reserve	43,211
Non-Qualified Pension Plan	24,865
Performance Recognition Awards	4,954
Performance Share Plan	10,472
Post Employment Benefits - FAS 106	1,797,510
Post Employment Benefits - FAS 112	100,279
State Tax Deduction	27,601
Texas Margin Tax	(23,834)
Vacation Accrual	219,753
Total Electric	$45,746,248

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Sharing Unrealized MTM Prop	2,332,446	1,840,289	456	4,172,735	
2	Margins					
3	Long-term Income Tax and	462,597	3,162	Various	302,347	163,412
4	Interest Receivable					
5	Debt Issuance Expense	66,121	1,341,941	Various	1,388,062	20,000
6	Amortization over life of					
7	issued bonds					
8	2016 Texas Elec Rate Case Cost	1,402,374		928	1,526,407	-124,033
9	Docket No. 45524					
10						
11	2016 Texas Fuel Reconcilation	625,699	-625,699	928		
12	Docket No. 40625					
13						
14	Prepaid Retiree Medical	99,514	791,000	228.3	481,514	409,000
15						
16	Texas DSM Incentives	1,173,019	1,070,142	182.3	1,187,974	1,055,187
17						
18	2017 TX TCRF	179,810	-179,810	928		
19	Docket No. 46877					
20						
21	2017 TX Electric Rate Case	1,450,000	840,588	928	837,649	1,452,939
22	Docket No. 47527					
23						
24	2017 NM Supreme Court Case	451	395	928	846	
25	Case No. S-1-SC-36466					
26						
27	2017 NM Retail Rate Case	1,150,897	25	928	928,994	221,928
28	Case No. 17-00255-UT					
29						
30	Prepaid Facility Fees	860,517	1,715,126	431	1,064,783	1,510,860
31						
32	Tx Electric 2017 Surcharge	19,017	-19,017	928		
33	Docket No. 47035					
34						
35	2018 TX Fuel Reconciliation	331,049	1,112,670			1,443,719
36	Docket No. 48973					
37						
38	Other Texas Dockets	67,648	576,364	928	46,998	597,014
39						
40	SPS TX 2019 Retail Rate Case &	188,068	15,012,701			15,200,769
41	Cost Deferrals					
42	SPS NM 2018 E Supreme Court	96,670	34,173	928	130,843	
43	Case No. S-1-SC-37308					
44						
45	SPS NM 2019 Retail Rate Case	3,764	1,254,913			1,258,677
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	10,509,661				23,209,472

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: c

This account is used to record an estimated impact of JOA allocations and estimated rate payer sharing on a forward Mark-to-Market position. Credit balances are adjustments and are not amortizations nor write-offs.

Schedule Page: 233 Line No.: 1 Column: e

This account is used to record an estimated impact of JOA allocations and estimated rate payer sharing on a forward Mark-to-Market position. Credit balances are adjustments and are not amortizations nor write-offs.

Schedule Page: 233 Line No.: 3 Column: e

Account charged:

409.1	$299,182
431	3,165
	$302,347

Schedule Page: 233 Line No.: 5 Column: e

Account charged:

181	$ 1,378,634
903	257
921	50
232	9,121
	$ 1,388,062

Schedule Page: 233 Line No.: 11 Column: c

Unnatural Debit Balance: (625,699)
The credit to the rate case expense account represents a reclass to line 21, to consolidate balances per regulatory filings. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Schedule Page: 233 Line No.: 18 Column: c

Unnatural Debit Balance: (179,810)
The credit to the rate case expense account represents a reclass to line 21, to consolidate balances per regulatory filings. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Schedule Page: 233 Line No.: 32 Column: c

Unnatural Debit Balance: (19,017)
The credit to the rate case expense account represents a reclass to line 21, to consolidate balances per regulatory filings. As such, it is a reduction of the deferred balance separate from amounts that have been amortized or written off.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Unrecognized Tax Benefits	133,176	138,789
3	Electric Nonplant	49,048,650	192,108,000
4	Electric Plant	84,867,647	87,485,289
5	Regulatory Differences - Excess Deferred Plant Taxes	-32,698,931	-31,189,102
6	Regulatory Differences - Deferred ITC	44,640	29,849
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	101,395,182	248,572,825
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	-2	-2
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	101,395,180	248,572,823

Notes

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 4 Column: c

	12/31/2018	12/31/2019
Regulatory Difference - Effect of Rate Changes	(33,175,437)	(31,576,355)
Electric Deferral of TCJA Benefit (ARAM)	476,506	387,253
	(32,698,931)	(31,189,102)
Regulatory Difference - ITC Grossup	44,640	29,849
Total Electric Plant Related Only	(32,654,291)	(31,159,253)

Schedule Page: 234 Line No.: 5 Column: c

Amortization of Excess ADIT (Electric only) included in 410.1 is $1,112,754 in 2018 and $979,115 in 2019.

	2018	2019
Electric Distribution Plant	$ 507,045	$ 475,206
Electric General Plant	29,680	26,296
Electric Intangible Plant	432	402
Electric Production Plant	139,301	115,864
Electric Transmission Plant	436,296	361,347
Total ARAM	$ 1,112,754	$ 979,115

The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

Excess (Electric only)	Dec. 31, 2019 Excess	Dec. 31, 2019 Gross up	Dec. 31, 2019 Total Regulatory
Flow Through	270,317	76,967	347,284
Other Basis Differences (Unprotected)	(24,852,650)	(7,070,989)	(31,923,639)
Total	(24,582,333)	(6,994,022)	(31,576,355)

Schedule Page: 234 Line No.: 8 Column: c

	12/31/2018	12/31/2019
Electric Distribution Plant	$ 36,158,388	$ 36,267,446

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) _ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Electric General Plant	948,926	928,210
Electric Production Plant	8,624,128	11,381,135
Electric Transmission Plant	38,972,736	38,752,333
Electric Transmission-Production Plant	163,469	156,165
Regulatory Difference - Excess Deferred Taxes	(32,698,931)	(31,189,102)
Regulatory Difference - Deferred ITC	44,640	29,849
TOTAL Electric Plant	$ 52,213,356	$ 56,326,036

Accumulated Deferred Income Taxes (Account 190). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances on regulatory differences related to income taxes. An adjustment is made to include the regulatory asset balance related to nonplant accumulated deferred income taxes.

Schedule Page: 234 Line No.: 18 Column: c

Refer to FERC page 232 for SPS's regulatory asset related to nonplant excess ADIT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201: Common Stock	200	1.00	
2	All SPS Common stock owned by its parent,			
3	Xcel energy			
4				
5				
6				
7	Total Common	200		
8				
9	Account 204: Preferred Stock	10,000,000	1.00	1.00
10				
11				
12				
13				
14				
15	Total Preferred	10,000,000		
16				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
100	100					1
						2
						3
						4
						5
						6
100	100					7
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Miscellaneous paid-in capital	1,997,779,212
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40	TOTAL	1,997,779,212

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	9,033,435
2		
3		
4		
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21		
22	TOTAL	9,033,435

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Bonds		
2	3.70% Aug 15, 2047 First Mortgage Bonds	450,000,000	5,056,507
3			2,587,500 D
4	3.40% Aug 15, 2046 First Mortgage Bonds	300,000,000	3,511,006
5			507,000 D
6	4.40% Nov 15, 2048 First Mortgage Bonds	300,000,000	3,524,579
7			1,935,000 D
8	4.50% Aug 15, 2041 Secured First Mortgage Bonds	200,000,000	3,848,628
9			3,014,000 D
10	4.50% Aug 15, 2041 Secured First Mortgage Bonds	100,000,000	1,380,528
11			-10,058,000 P
12	4.50% Aug 15, 2041 Secured First Mortgage Bonds	100,000,000	1,307,249
13			4,088,000 D
14	3.30% Jun 15, 2024 Secured First Mortgage Bonds	150,000,000	1,445,554
15			495,000 D
16	3.30% Jun 15, 2024 Secured First Mortgage Bonds	200,000,000	2,028,826
17			-596,000 P
18			
19	3.75% Jun 15, 2049 Secured First Mortgage Bonds	300,000,000	3,584,206 D
20			3,783,000
21	Total Account 221	2,100,000,000	31,442,583
22			
23	Account 224 - Other Long Term Debt		
24			
25	6.00% Oct 1, 2033 Unsecured Series C and D Senior Notes	100,000,000	1,237,091
26			810,000 D
27	6.00% Oct 1, 2036 Unsecured Series F Senior Notes	250,000,000	2,596,882
28			1,922,500 D
29			
30	Total Account 224	350,000,000	6,566,473
31			
32	Interest on Debt to Associated Companies		
33	TOTAL	2,450,000,000	38,009,056

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
	/					1
08/09/2017	08/15/2047	08/09/2017	08/15/2047	450,000,000	16,650,000	2
						3
8/12/2016	8/15/2046	8/12/2016	8/15/2046	300,000,000	10,200,000	4
						5
11/05/2018	11/15/2048	11/05/2018	11/15/2048	300,000,000	13,200,000	6
						7
8/10/2011	8/15/2041	8/10/2011	8/15/2041	200,000,000	9,000,000	8
						9
6/12/2012	8/15/2041	6/12/2012	8/15/2041	100,000,000	4,500,000	10
						11
8/20/2013	8/15/2041	8/20/2013	8/15/2041	100,000,000	4,500,000	12
						13
6/09/2014	6/15/2024	6/09/2014	6/15/2024	150,000,000	4,950,000	14
						15
9/16/2015	6/15/2024	9/16/2015	6/15/2024	200,000,000	6,600,000	16
						17
						18
6/18/2019	6/15/2049	6/18/2019	6/15/2049	300,000,000	6,031,250	19
						20
				2,100,000,000	75,631,250	21
						22
						23
						24
10/6/2003	10/1/2033	10/6/2003	10/1/2033	100,000,000	6,063,181	25
						26
10/6/2006	10/1/2036	10/6/2006	10/1/2036	250,000,000	15,000,000	27
						28
						29
				350,000,000	21,063,181	30
						31
					862,225	32
				2,450,000,000	97,556,656	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 19 Column: a

New Mexico Public Regulation Commission case no. 19-00038-UT. Order dated March 6, 2019

In June 2019, SPS issued $300,000,000 of 3.75 percent First Mortgage Bonds, due June 15, 2049. SPS used the net proceeds to finance or refinance, existing and future Eligible Green Expenditures.

Schedule Page: 256 Line No.: 25 Column: i

Interest at state rate	$6,000,000
Interest at swap loss	$63,181
	$6,063,181

Schedule Page: 256 Line No.: 32 Column: i

Xcel Energy Services Inc	$666,851
Money Pool	$195,374
	$862,225

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	263,067,322
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote for Details	10,275,388
6		
7	Reconciling Items for the Year: Total Income Tax Expense	25,617,201
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote for Details	323,961,932
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote for Details	-26,812,101
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote for Details	-591,271,933
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	4,837,809
28	Show Computation of Tax:	
29	Federal Income Tax @ 21%	1,015,940
30		
31	Other	-4,331,886
32		
33	TOTAL Net Federal Income Tax Accrual	-3,315,946
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Reported On Books	
Gain/(Loss) on Disposition of Assets (Tax)	$2,062,670
Provision for Contributions in Aid of Construction	8,212,718
	$10,275,388

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted For Return	
Avoided Cost Interest	$22,164,641
Book Depreciation Provision	224,666,022
Book Unamortized Cost of Reacquired Debt	807,614
Clearing Account Book Expense	7,222,910
Club Dues	29,000
Deferred Compensation Plan Reserve	1,321,576
Deferred Fuel Costs	25,456,263
Employee Stock Ownership Plan Dividends	609,902
Environmental Remediation	534,724
Inventory Reserve	16,338
Interest Income/Expense on Disputed Tax	188,084
Litigation Reserve	75,000
Lobbying Expenses	720,000
Mark-to-Market Adjustment	2,438,688
Meals and Entertainment	928,000
Pension & Benefits Capitalized	2,410,326
Penalties	108,646
Performance Recognition Awards	10,786
Performance Share Plan	60,675
Recoverable Meters Provision	34,898
Regulatory Asset - Miscellaneous	1,873,293
Regulatory Asset - Texas Surcharge	5,633,233
Renewable Energy Standard/Credit	5,476,613
Section 174 - Section 59(e) Adjustment	11,469,614
State Tax Deduction	9,660,115
Suite / Entertainment Tickets	20,000
Vacation Accrual	24,971
	$323,961,932

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded On Books Not Included In Return	
Allowance for Funds During Construction (AFDC) - Equity	$(26,799,567)
Deferred Revenue - Investment Tax Credit (ITC) Grant	(12,534)
	$(26,812,101)

Schedule Page: 261 Line No.: 20 Column: b

Deductions On Return Not Charged Against Book Income	
Allowable Depreciation	$(446,587,616)
Allowance for Funds During Construction (AFDC) - Debt	(12,318,499)
Bad Debts	(310,544)
Demand Side Management	(1,506,012)
Contributions Carryover	(278,419)
Employee Incentive	(34,732)
Internally Developed Software	(47,721)
Non-Qualified Pension Plan	(11,178)
Pension Expense	(3,220,852)
Post Employment Benefit - Long Term Disability	(213,829)
Post Employment Benefit - Retiree Medical	(397,016)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/02/2020	2019/Q4

FOOTNOTE DATA

Rate Case / Restructuring	(14,578,940)
Rate Refund Reserve	(6,343,979)
Regulatory Asset / Liability - Transmission Attach O	(4,424,215)
Repair Expenditures	(49,300,000)
Section 174 Expenditures	(16,700,000)
Tax Removal Cost Over Book	(34,998,381)
	$(591,271,933)

Schedule Page: 261 Line No.: 33 Column: b

Southwestern Public Service Company is a member of an affiliated group which will file a consolidated federal income tax return for the year 2019. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	$(39,726,114)
Northern States Power Company (Minnesota) and Subsidiaries	83,371,558
Northern States Power Company (Wisconsin) and Subsidiaries	6,057,334
Public Service Company of Colorado and Subsidiaries	(6,866,138)
Nicollet Holdings Company, LLC and Subsidiaries	1,143,742
Nicollet Projects Holdings Company, LLC and Subsidiaries	(2,249,851)
Xcel Energy Communications Group Inc. and Subsidiaries	(53,676)
Xcel Energy Markets Holdings Inc. and Subsidiaries	(510,642)
Xcel Energy International Inc.	(345)
Xcel Energy Retail Holdings Inc. and Subsidiaries	(3,631)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(38,874)
Xcel Energy Ventures Inc. and Subsidiaries	(24,540,198)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	588,212
Xcel Energy Wholesale Group Inc. and Subsidiaries	(32,794,186)
Xcel Energy WYCO Inc.	5,104,227
WestGas Interstate, Inc.	23,638
Xcel Energy Services Inc.	4,350,474

The consolidated federal income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income (2141001)	9,261,894		-3,971,506	-2,226,651	-497,619
3	Income Tax Adjustment			655,560		-655,560
4	2018 Federal Unemployment	826			826	
5	2019 Federal Unemployment			53,748	51,693	
6	2018 FICA (2146001)					
7	2019 FICA (2146001)	553,023		8,524,705	8,488,915	
8	Subtotal	9,815,743		5,262,507	6,314,783	-1,153,179
9						
10	STATE:					
11	2018 State Unemployment	2,191			2,191	
12	2019 State Unemployment			79,579	76,370	
13	Subtotal	2,191		79,579	78,561	
14						
15	TEXAS:					
16	Income (2141011)	2,877,905		1,447,942	-12,443,767	-14,763,884
17	Income Tax Adjustment			26,730		-26,730
18	Franchise					
19	Use (2154001)					
20	2018 Property Tax (2144001)	22,090,830		-364,674	21,726,156	
21	2019 Property Tax (2144001)			35,629,854	13,366,414	1,090,146
22	Gross Receipts (1244001)			6,060,630	6,060,630	
23	Subtotal	24,968,735		42,800,482	28,709,433	-13,700,468
24						
25	NEW MEXICO:					
26	Income (2141011)	1,165,490		-701,279	2,693,594	2,229,383
27	Income Tax Adjustment					
28	Franchise					
29	Use (2145001)					
30	2018 Property Tax (2144001)	4,465,976		-51,952	4,414,024	
31	2019 Property Tax (2144001)			11,605,000	5,840,723	155,000
32	Subtotal	5,631,466		10,851,769	12,948,341	2,384,383
33						
34	OKLAHOMA:					
35	Income (2141011)	68,665		-68,908		243
36	Income Tax Adjustment					
37	Franchise (1244001)			20,000	20,000	
38	Use (2145001)					
39	2018 Property Tax (2144001)					
40	2019 Property Tax (2144001)			593,118	593,118	
41	TOTAL	42,497,226		80,813,327	69,734,006	-12,357,034

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year	Taxes Paid During Year	Adjust-ments
		Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(f)
1	Subtotal	68,665		544,210	613,118	243
2						
3	KANSAS:					
4	Income (2141011)	47,451		-72,240	90,058	114,847
5	Income Tax Adjustment					
6	Franchise					
7	Use (2145001)					
8	2018 Property Tax (2144001)					
9	2019 Property Tax (2144001)			1,231,549	1,231,549	
10	SUBTOTAL	47,451		1,159,309	1,321,607	114,847
11						
12	OTHER:					
13	Miscellaneous Tax			5,775	5,775	
14	Citry Franchise Fees	1,274,161		8,752,025	8,760,940	-2,860
15	SPS Use Tax (2145002)	688,814		11,357,671	10,981,448	
16	Subtotal	1,962,975		20,115,471	19,748,163	-2,860
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	42,497,226		80,813,327	69,734,006	-12,357,034

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
7,019,419		-4,304,579			333,073	2
		655,560				3
		826				4
2,055		53,258			-336	5
						6
588,814		8,502,275			22,430	7
7,610,288		4,907,340			355,167	8
						9
						10
		2,191				11
3,209		120,224			-42,836	12
3,209		122,415			-42,836	13
						14
						15
2,005,730		1,447,942				16
		26,730				17
						18
						19
		-364,674				20
23,353,586		35,617,854			12,000	21
		6,060,630				22
25,359,316		42,788,482			12,000	23
						24
						25
		-722,734			21,455	26
						27
						28
						29
		-51,952				30
5,919,277		11,605,000				31
5,919,277		10,830,314			21,455	32
						33
						34
		-69,376			468	35
						36
		20,000				37
						38
						39
		593,118				40
41,219,513		69,132,779			11,680,548	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		543,742			468	1
						2
						3
		-72,550			310	4
						5
						6
						7
						8
		1,231,549				9
		1,158,999			310	10
						11
						12
		5,775				13
1,262,386		8,752,025				14
1,065,037		23,687			11,333,984	15
2,327,423		8,781,487			11,333,984	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
41,219,513		69,132,779			11,680,548	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: f

Federal income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	$	(296,020)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)		(201,599)
	$	(497,619)

Schedule Page: 262 Line No.: 2 Column: l

Federal non-operating income tax - non-utility (409.2)	$	333,073
	$	333,073

Schedule Page: 262 Line No.: 3 Column: f

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$	(6,945)
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(648,615)
	$	(655,560)

Schedule Page: 262 Line No.: 5 Column: l

Federal Unemployment charged to capital , clearing and deferred accounts (107,184,186)	$	(348)
Federal Unemployment Non Utility (408.2)		12
	$	(336)

Schedule Page: 262 Line No.: 7 Column: l

FICA taxes charged to capital, clearing and deferred accounts (107,184,186)	$	20,630
Payroll Taxes Non Utility (408.2)		1,800
	$	22,430

Schedule Page: 262 Line No.: 12 Column: l

State Unemployment charged to capital , clearing and deferred accounts (107,184,186)	$	(42,876)
State Unemployment Non Utility (408.2)		40
	$	(42,836)

Schedule Page: 262 Line No.: 16 Column: f

State income tax expense(accrual and cash) for audit in other accounts receivable (143)	$	(14,154,939)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)		(608,945)
	$	(14,763,884)

Schedule Page: 262 Line No.: 17 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	$	(26,730)
	$	(26,730)

Schedule Page: 262 Line No.: 21 Column: f

Texas property tax on CWIP reclassified to a capital asset	$	1,090,146
	$	1,090,146

Schedule Page: 262 Line No.: 21 Column: l

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Property taxes - Non Utility (408.2)	$	12,000
	$	12,000

Schedule Page: 262 Line No.: 26 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$	(14,561)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)		1,454,324
State income tax expense accrual in other accounts receivable (143)		789,620
	$	2,229,383

Schedule Page: 262 Line No.: 26 Column: l

State non-operating income tax - non-utility (409.2)	$	21,455
	$	21,455

Schedule Page: 262 Line No.: 31 Column: f

New Mexico property tax on CWIP reclassified to a capital asset	$	155,000
	$	155,000

Schedule Page: 262 Line No.: 35 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$	(293)
State income tax expense accrual in other accounts receivable (143)		536
	$	243

Schedule Page: 262 Line No.: 35 Column: l

State non-operating income tax - non-utility (409.2)	$	468
	$	468

Schedule Page: 262.1 Line No.: 1 Column: l

State non-operating income tax - non-utility (409.2)	$	468
	$	468

Schedule Page: 262.1 Line No.: 4 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	$	(202)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)		114,616
State income tax expense accrual in other accounts receivable (143)		433
	$	114,847

Schedule Page: 262.1 Line No.: 4 Column: l

State non-operating income tax - non-utility (409.2)	$	310
	$	310

Schedule Page: 262.1 Line No.: 14 Column: f

City franchise fee adjustments - Franchise Fees (408.1) tax collections payable (241)	$	(2,860)
	$	(2,860)

Schedule Page: 262.1 Line No.: 15 Column: l

Use tax accrued on taxable materials and services	$	11,333,984
	$	11,333,984

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Retail	157,285			411.4	52,421	
7							
8	TOTAL	157,285				52,421	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
104,864			6
			7
104,864			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			31
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			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Comp Liabilities	2,687,729	131	64,301	1,385,877	4,009,305
2						
3	Remediation & Other Deferred Costs	50,000	Various	48,295	582,860	584,565
4						
5	Executive PSP Long-Term	219,880	Various	183,479	162,980	199,381
6						
7	Long-term Income Tax and	1,147,028	409.1	81,935	972,078	2,037,171
8	Interest Payable					
9	Deferred Revenue - ITC Grant	206,812	417.1	12,534		194,278
10	25 year amortization beginning					
11	2010 and ending 2035					
12						
13	Miscellaneous Deferred Credit	4,685,685	158.1	3,136,117	2,204,337	3,753,905
14						
15	Customper Prepayments - Capital	146,428	Various	143,978	25,000	27,450
16	CIAC					
17	Deferred Revenue for Tax Liability	4,096,085	405	240,755	805,338	4,660,668
18	for CIAC					
19	MTM Unrealized JOA				106,243	106,243
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	13,239,647		3,911,394	6,244,713	15,572,966

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 3 Column: d

Contra Account (c)	Amount (d)
242	$ 15,800
407.3	32,495
	$ 48,295

Schedule Page: 269 Line No.: 5 Column: d

Contra Account (c)	Amount (d)
920	$ 1,367
232	178,628
234	3,484
	$ 183,479

Schedule Page: 269 Line No.: 15 Column: d

Contra Account (c)	Amount (d)
107	$ 130,375
241	13,603
	$ 143,978

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	1,127,055	-28,686	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	1,127,055	-28,686	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	1,127,055	-28,686	
18	Classification of TOTAL			
19	Federal Income Tax	1,079,205	-27,467	
20	State Income Tax	47,850	-1,219	
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						1,098,369	4
							5
							6
							7
						1,098,369	8
							9
							10
							11
							12
							13
							14
							15
							16
						1,098,369	17
							18
						1,051,738	19
						46,631	20
							21

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 272 Line No.: 4 Column: b

All amounts in columnbs b - k are related to Electric Steam Production Plant

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,175,821,592	65,635,386	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,175,821,592	65,635,386	
6		-569,591,494		
7		27,882,557		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	634,112,655	65,635,386	
10	Classification of TOTAL			
11	Federal Income Tax	574,676,955	59,209,120	
12	State Income Tax	59,435,700	6,426,266	
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						1,241,456,978	2
							3
							4
						1,241,456,978	5
		254	42,375	254	15,955,922	-553,677,947	6
				182.3	6,179,833	34,062,390	7
							8
			42,375		22,135,755	721,841,421	9
							10
					19,600,438	653,486,513	11
			42,375		2,535,317	68,354,908	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 6 Column: b

Prior Flow Through

Schedule Page: 274 Line No.: 6 Column: k

The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

	Dec. 31, 2019	Dec. 31, 2019	Dec. 31, 2019
Excess (Electric only)	Excess	Gross up	Total Regulatory
Flow Through	(366,544)	(104,366)	(470,910)
Method Life (Protected)	(354,585,670)	(100,960,397)	(455,546,067)
Other Basis Differences (Unprotected)	(76,016,857)	(21,644,113)	(97,660,970)
Total	(430,969,071)	(122,708,876)	(553,677,947)

The Amortization of Excess ADIT included above in 410.1 is $11,634,011 for 2018 and $10,974,252 for 2019

	2018 ARAM	2019 ARAM
Electric Distribution Plant	2,157,362	2,232,883
Electric General Plant	2,007,697	2,316,595
Electric Intangible Plant	1,092,839	1,514,196
Electric Production Plant	4,235,071	3,206,384
Electric Transmission Plant	2,141,042	1,704,194
Total ARAM	11,634,011	10,974,252

Schedule Page: 274 Line No.: 7 Column: b

AFUDC Equity

Schedule Page: 274 Line No.: 9 Column: k

	12/31/2018	410.1 & Adjustments	12/31/2019
Electric Distribution Plant	$ 263,182,336	$ 3,060,918	$ 266,243,254
Electric General Plant	59,791,458	(2,224,466)	$ 57,566,992
Electric Intangible Plant	1,348,895	(87,932)	$ 1,260,963
Electric Production Plant	272,599,719	24,544,602	$ 297,144,321
Electric Transmission Plant	571,256,309	40,465,473	$ 611,721,782
Electric Transmission-Production Plant	4,578,545	(111,420)	$ 4,467,125
Non-Utility	3,064,330	(11,789)	$ 3,052,541
Regulatory Difference - Prior Flow Thru	(569,591,494)	15,913,547	$ (553,677,947)
Regulatory Difference - AFUDC Equity	27,882,557	6,179,833	$ 34,062,390
TOTAL Electric Plant	$ 634,112,655	$ 87,728,766	$ 721,841,421

FERC Account	Description	Page No.	Plant-Related Ending Balance
282	Accumulated Deferred Income Taxes - Other Property	275	$ 721,841,421
	Less: Non-utility Accumulated Deferred Income Taxes		(3,052,541)

Name of Respondent	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company		04/02/2020	2019/Q4

FOOTNOTE DATA

Unblended ADIT Adjustment Total Company - Wholesale Jurisdiction	(38,987,231)
Wholesale Jurisdiction Accumulated Deferred Income Taxes	679,801,649

Other items included in Plant-282 Balance:

Texas Gross Margin Tax	13,776,999
Restructuring Meters	(435,587)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric Non-Plant	56,580,065	125,355,680	9,576,215
4	Electric Plant	26,596,986	-1,926,819	
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	83,177,051	123,428,861	9,576,215
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18		-244,625		1
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	82,932,426	123,428,861	9,576,216
20	Classification of TOTAL			
21	Federal Income Tax	79,083,277	115,218,462	9,208,978
22	State Income Tax	3,849,149	8,210,399	367,238
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		254	8,405,415	various	6,134,984	170,089,099	3
						24,670,167	4
							5
							6
							7
							8
			8,405,415		6,134,984	194,759,266	9
							10
							11
							12
							13
							14
							15
							16
							17
						-244,626	18
			8,405,415		6,134,984	194,514,640	19
							20
			8,405,415		6,134,984	182,822,330	21
						11,692,310	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 3 Column: i

254 & 219.1

Schedule Page: 276 Line No.: 4 Column: b

	12/31/2018	410.1	12/31/2019
Electric General Plant	213,131	(14,739)	198,392
Electric Intangible Plant	26,383,855	(1,912,080)	24,471,775
TOTAL Electric Plant	26,596,986	(1,926,819)	24,670,167

Schedule Page: 276 Line No.: 19 Column: k

Refer to FERC page 278 for SPS's regulatory liability related to nonplant excess ADIT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Deferred Investment Tax Credit	44,641	190	14,791		29,850
2						
3	'Texas Fuel Costs Recovered via FCR	25,978,901	557	244,908,763	273,652,779	54,722,917
4						
5	New Mexico Fuel Costs - NMPRC	30,533,448	557	110,017,853	106,409,262	26,924,857
6	'Rule 550 - Recovered via FPPCAC					
7						
8	DSM Texas Energy Efficiency	151,662	908	91,337	921,710	982,035
9	Docket 48324					
10						
11	DSM New Mexico Energy Efficiency				1,487,313	1,487,313
12						
13	Attachment 'O' Transmission Refund	11,674,283	Various	7,184,010	5,674,222	10,164,495
14						
15	2019 Production Formula True-up	7,803,308	447	8,183,989	5,850,756	5,470,075
16						
17	Retiree Medical Liability	11,397,456	Various	886,000	2,734,985	13,246,441
18						
19	Sale of Lubbock Distribution Assets:	2,422,458	407.4	53,949		2,368,509
20	Incremental Capital Expenditures & Other					
21	Amortized over life of the asset					
22	Docket #37901					
23						
24	SO2 Reserve	18			16	34
25	Docket #08-00354-UT					
26						
27	FAS 133-Elec Hedges	14,658,453	175	2,938,307		11,720,146
28						
29	New Mexico RPS Rider	2,438,881	Various	14,343,233	18,854,924	6,950,572
30	Case #18-00208-UT					
31						
32	Prior Flow Thru and Excess ADIT	538,679,065	Various	14,759,295		523,919,770
33						
34	Nonplant Excess ADIT	23,017,108	190	10,257,310	5,144,062	17,903,860
35						
36	New Mexico TCJA Refund	10,190,215	456	10,190,215		
37	Case #17-00255-UT					
38						
39						
40						
41	TOTAL	678,989,897		423,829,052	420,730,029	675,890,874

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 13 Column: d

Accounts charged:

456.1	$5,654,139
565	1,529,871
	$7,184,010

Schedule Page: 278 Line No.: 17 Column: d

Accounts charged:

228.3	$ 581,000
926	305,000
	$ 886,000

Schedule Page: 278 Line No.: 29 Column: d

Account charged:

182.3	$ 1,929,898
407.4	1,851,317
456	105
557	10,561,913
	$ 14,343,233

Schedule Page: 278 Line No.: 32 Column: d

Account charged:

182.3	$ 444,829
190	404,804
282	13,909,662
	$ 14,759,295

Schedule Page: 278 Line No.: 34 Column: b

Electric	$ 24,489,267
Reserve	(1,472,159)
	$ 23,017,108

The total related to nonplant excess ADIT is $24,489,267. This amount would be included as a decrease to rate base for purposes of calculating SPS formula rates, as applicable.

Schedule Page: 278 Line No.: 34 Column: f

	Excess Nonplant ADIT - Regulatory Liability*	Gross-Up	Reserves (Net of Gross-Up)	Total
Electric	$ 15,082,575	$ 4,294,430	$(1,473,145)	$ 17,903,860
Total	$ 15,082,575	$ 4,294,430	$(1,473,145)	$ 17,903,860

*Total nonplant excess ADIT is $15,082,275. This amount would be included as a decrease to rate base for purposes of calculating SPS formula rates, as applicable.

The Nonplant Excess Accumulated Deferred Income Taxes above include the following ungrossed amounts:

Book Unamortized Cost of Reacquired Debt	
Pension Expense	$ 2,941,267
Rate Case / Restructuring Expense	17,488,728
Regulatory Asset - New Mexico Nitric Oxide (NOX)	2,315,093
State Tax Deduction	4,492
Total Electric	175,345
	$ 22,924,925

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	367,171,474	376,525,460
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	365,352,993	377,998,521
5	Large (or Ind.) (See Instr. 4)	470,100,557	474,205,317
6	(444) Public Street and Highway Lighting	6,958,998	7,043,700
7	(445) Other Sales to Public Authorities	36,001,356	39,101,436
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,245,585,378	1,274,874,434
11	(447) Sales for Resale	302,197,986	396,011,244
12	TOTAL Sales of Electricity	1,547,783,364	1,670,885,678
13	(Less) (449.1) Provision for Rate Refunds	3,874,351	
14	TOTAL Revenues Net of Prov. for Refunds	1,543,909,013	1,670,885,678
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,509,967	1,660,527
17	(451) Miscellaneous Service Revenues	876,832	1,158,183
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	8,467,151	8,553,339
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-28,983,035	-9,549,747
22	(456.1) Revenues from Transmission of Electricity of Others	246,772,961	222,965,402
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	228,643,876	224,787,704
27	TOTAL Electric Operating Revenues	1,772,552,889	1,895,673,382

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
3,656,212	3,645,138	310,514	307,894	2
				3
5,095,598	5,040,877	77,585	77,275	4
11,732,482	11,214,454	246	227	5
43,138	47,250	113	116	6
499,630	502,781	6,211	6,202	7
				8
				9
21,027,060	20,450,500	394,669	391,714	10
8,787,530	10,077,040	7	7	11
29,814,590	30,527,540	394,676	391,721	12
				13
29,814,590	30,527,540	394,676	391,721	14

Line 12, column (b) includes $ -2,126,923 of unbilled revenues.
Line 12, column (d) includes 50,306 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 2 Column: b

Current Year

		Billed Revenue	Unbilled Revenue	Total
Residential	440	368,327,126	(1,155,652)	367,171,474
Small C&I	442	364,775,827	577,167	365,352,994
Large C&I	442	472,332,129	(2,231,572)	470,100,557
PSHL	444	6,960,725	(1,727)	6,958,998
OSPA	445	36,074,947	(73,592)	36,001,355
Resale	447	301,439,533	758,453	302,197,986
		1,549,910,287	(2,126,923)	1,547,783,364
				-

This note applies to column (b), rows 2, 4, 5, 6, 7, and 11.

Schedule Page: 300 Line No.: 2 Column: c

Previous Year

		Billed Revenue	Unbilled Revenue	Total
Residential	440	379,117,026	(2,591,566)	376,525,460
Small C&I	442	379,546,597	(1,548,076)	377,998,521
Large C&I	442	477,079,551	(2,874,233)	474,205,318
PSHL	444	7,068,444	(24,745)	7,043,699
OSPA	445	39,397,553	(296,117)	39,101,436
Resale	447	394,361,311	1,649,934	396,011,245
		1,676,570,482	(5,684,803)	1,670,885,679

This note applies to column (c), rows 2, 4, 5, 6, 7, and 11.

Schedule Page: 300 Line No.: 5 Column: b

Commercial and industrial sales are classified as "large" for purposes of this report if the customer has a minimum registered demand of 1,000 KW or more.

Schedule Page: 300 Line No.: 5 Column: c

Commercial and industrial sales are classified as "large" for purposes of this report if the customer has a minimum registered demand of 1,000 KW or more.

Schedule Page: 300 Line No.: 13 Column: b

Provision in 2019 due to new rates under ER19-404

Schedule Page: 300 Line No.: 13 Column: c

No provisioins in 2018

Schedule Page: 300 Line No.: 17 Column: b

Account charged:

Customer Connections	$568,198
Return Check Charge	204,899
Penalties	-
Other	103,735
	$876,832

Schedule Page: 300 Line No.: 17 Column: c

Account charged:

Customer Connections	$ 883,167
Return Check Charge	199,303

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Penalties	0
Other	75,713
	$1,158,183

Schedule Page: 300 Line No.: 21 Column: b

	Current Year
Mutual Aid	$ -
JOA Margin Sharing	1,198,244
Distrib Service Charge-Coops-Whl	461,714
CIP/DSM Incentive	224,886
Deferred Fuel Revenue	(25,135,425)
Reverse NM TCJA Accrual	10,190,215
PTC's	(15,997,442)
MISC Other	74,773
	$ (28,983,035)

Other Revenue includes the effect of sharing electric trading margins with affiliates Public Service Company of Colorado and Nothern States Power Co. (a Minnesota Company).

Schedule Page: 300 Line No.: 21 Column: c

	Previous Year
Mutual Aid	$ 4,233,339
JOA Margin Sharing	3,478,491
Distrib Service Charge-Coops-Whl	1,116,077
CIP/DSM Incentive	(330,955)
Deferred Fuel Revenue	(8,052,470)
NM TCJA Accrual	(10,190,215)
MISC Other	195,986
	$ (9,549,747)

Other Revenue includes the effect of sharing electric trading margins with affiliates Public Service Company of Colorado and Nothern States Power Co. (a Minnesota Company).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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21					
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23					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	TX Residential	1,976,553	208,904,211	177,379	11,143	0.1057
2	TX Res Space Heat	504,153	44,383,641	28,093	17,946	0.0880
3	TX Res Lighting	6,091	1,461,978	8,035	758	0.2400
4	TX Res Time of Use	647	64,213	42	15,405	0.0992
5	NM Residential	671,234	68,509,126	60,877	11,026	0.1021
6	NM Res Space Heat	497,025	43,933,180	29,755	16,704	0.0884
7	NM Res Lighting	4,992	1,058,035	6,322	790	0.2119
8	NM Res Time of Use	179	12,742	11	16,273	0.0712
9	Residential Unbilled	-4,662	-1,155,652			0.2479
10	TOTAL RESIDENTIAL	3,656,212	367,171,474	310,514	11,775	0.1004
11						
12	NM Commercial Area Lighting	10,320	1,394,385	2,761	3,738	0.1351
13	TX Flood Lighting	11,246	1,378,522	1,195	9,411	0.1226
14	TX Guard Lighting	6,639	1,610,999	4,356	1,524	0.2427
15	NM General Service Time of Use	194	29,055	1	194,000	0.1498
16	TX General Serv Secondary Low Loa	78,924	243,506	1	78,924,000	0.0031
17	TX Gen Svc Experimental TOU	99,095	4,842,680	39	2,540,897	0.0489
18	NM Irrigation	72,575	5,815,745	1,005	72,214	0.0801
19	NM Large Gen Serv Trans - 115 kV	2,520,222	96,420,511	30	84,007,400	0.0383
20	TX Large Gen Serv Trans - 115 kV	4,117,579	199,174,247	50	82,351,580	0.0484
21	NM Large Gen Serv Trans - 69 kV	156,779	6,661,340	5	31,355,800	0.0425
22	TX Large Gen Serv Subtran - 69 kV	1,845,946	24,284,624	9	205,105,111	0.0132
23	NM Primary General	1,533,919	87,257,311	523	2,932,924	0.0569
24	NM Primary General Oil Well Pumpi	423,000	32,858,094	4,356	97,107	0.0777
25	TX Primary General	1,558,679	75,667,706	512	3,044,295	0.0485
26	TX Primary General Oil Well Pumpi	371,653	21,041,371	3,104	119,734	0.0566
27	TX Primary Qualifying Fac	91	44,738			0.4916
28	SAS-12 WRB Refining	122,391	19,663,800	1	122,391,000	0.1607
29	SAS-4 Canadian River Water Auth	43,148	4,920,267	1	43,148,000	0.1140
30	SAS-8 JM Huber	981	1,154,087	1	981,000	1.1764
31	NM Secondary General	743,775	57,697,746	3,856	192,888	0.0776
32	NM Small General Service	160,329	14,151,568	11,855	13,524	0.0883
33	TX Small General Service	280,149	26,594,197	32,112	8,724	0.0949
34	TX Secondary General	2,103,267	148,082,501	12,056	174,458	0.0704
35	TX Trans QF Standby - 115kV	512,547	5,749,680	1	512,547,000	0.0112
36	TX Trans QF Standby - 69kV	1,656	369,275	1	1,656,000	0.2230
37	SM/LG C&I Unbilled	52,976	-1,654,405			-0.0312
38	TOTAL COMMERCIAL &	16,828,080	835,453,550	77,831	216,213	0.0496
39						
40						
41	TOTAL Billed	20,977,813	1,248,470,754	394,669	53,153	0.0595
42	Total Unbilled Rev.(See Instr. 6)	49,247	-2,885,376	0	0	-0.0586
43	TOTAL	21,027,060	1,245,585,378	394,669	53,278	0.0592

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	TX SA-810 Street and Hwy Ltg	60	7,538	3	20,000	0.1256
2	TX SA-805 Amarillo Hwy Ltg	107	5,486	2	53,500	0.0513
3	TX Street Ltg Restricted Outdoor	30,620	4,660,197	90	340,222	0.1522
4	NM Street Lighting	12,919	2,287,504	18	717,722	0.1771
5	PS & HL Unbilled	-568	-1,727			0.0030
6	TOTAL PUBLIC STREET & HWY	43,138	6,958,998	113	381,752	0.1613
7						
8	TX Small Municipal & School	20,380	1,827,778	2,836	7,186	0.0897
9	TX Large School	163,874	13,412,481	730	224,485	0.0818
10	TX Large Municipal	180,935	10,901,507	908	199,268	0.0603
11	NM Small Municipal & School	11,370	948,182	1,170	9,718	0.0834
12	NM Large Municipal & School	121,570	8,985,000	567	214,409	0.0739
13	OSPA Unbilled	1,501	-73,592			-0.0490
14	TOTAL PUBLIC AUTHORITY	499,630	36,001,356	6,211	80,443	0.0721
15						
16						
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36						
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38						
39						
40						
41	TOTAL Billed	20,977,813	1,248,470,754	394,669	53,153	0.0595
42	Total Unbilled Rev.(See Instr. 6)	49,247	-2,885,376	0	0	-0.0586
43	TOTAL	21,027,060	1,245,585,378	394,669	53,278	0.0592

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FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 40 Column: a

Schedule Page: 304.1 Line No.: 40 Column: c

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

NM Commercial Area Lighting	$	183,401
NM General Service Time of Use		3,252
NM Irrigation		1,133,037
NM Large Gen Serv Trans - 115 kV		41,445,621
NM Large Gen Serv Trans - 69 kV		2,575,815
NM Large Municipal & School		2,104,321
NM Primary General		26,931,546
NM Primary General Oil Well Pumping		7,451,610
NM Res Lighting		89,307
NM Res Space Heat		8,918,394
NM Res Time of Use		835
NM Residential		11,648,631
NM Secondary General		13,000,583
NM Small General Service		2,799,940
NM Small Municipal & School		202,535
NM Street Lighting		234,552
SAS-12 WRB Refining		8,867,933
SAS-4 Canadian River Water Auth		2,102,744
SAS-8 JM Huber		759,955
TX Flood Lighting		217,735
TX Gen Svc Experimental TOU		1,393,740
TX General Serv Secondary Low Load		18,785
TX Guard Lighting		128,536
TX Large Gen Serv Subtran - 69 kV		11,113,152
TX Large Gen Serv Trans - 115 kV		93,070,126
TX Large Municipal		479,992
TX Large School		5,618,849
TX Primary General		27,809,231
TX Primary General Oil Well Pumping		6,618,315
TX Res Lighting		117,749
TX Res Space Heat		9,153,873
TX Res Time of Use		11,563
TX Residential		35,116,075
TX SA-805 Amarillo Hwy Ltg		579,064
TX SA-810 Street and Hwy Ltg		2,009
TX Secondary General		36,888,300
TX Small General Service		5,219,044
TX Small Municipal & School		357,718
TX Street Ltg Restricted Outdoor		1,116
TX Trans QF Standby - 115kV		1,847,608
TX Trans QF Standby - 69kV		(15,353)
Total	$	366,201,239

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Central Valley Elec Cooperative, Inc.	RQ	RS114	76	118	110
2	Farmers' Elec Cooperative Inc., of NM	RQ	RS115	42	68	53
3	Lea County Elec Cooperative, Inc.	RQ	RS116	140	220	173
4	Roosevelt County Elec Cooperative, Inc	RQ	RS117	17	35	25
5	Tri-County Elec Cooperative	RQ	RS136	56	60	52
6	West Texas Municipal Power Agency	RQ	RS137	449	441	395
7	Lubbock Power and Light	RQ	RS138	170	N/A	N/A
8	Lubbock Power and Light	OS	RS3	N/A	N/A	N/A
9	Southwest Power Pool	OS	V3	N/A	N/A	N/A
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
586,665	5,993,032	14,432,516	8,111,022	28,536,570	1
186,115	3,750,807	4,555,086	4,151,862	12,457,755	2
902,558	11,095,488	22,017,464	13,447,698	46,560,650	3
97,199	1,286,299	2,433,783	1,775,490	5,495,572	4
379,953	4,498,090	9,291,974	4,156,600	17,946,664	5
1,073,524	13,726,812	25,124,908	14,689,223	53,540,943	6
425,240	8,481,297	10,609,241	18,505,842	37,596,380	7
1,764,372	6,720,000	41,955,018		48,675,018	8
3,371,904		43,743,832	7,644,602	51,388,434	9
					10
					11
					12
					13
					14
3,651,254	48,831,825	88,464,972	64,837,737	202,134,534	
5,136,276	6,720,000	85,698,850	7,644,602	100,063,452	
8,787,530	**55,551,825**	**174,163,822**	**72,482,339**	**302,197,986**	

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FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 2 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 3 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 4 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 5 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 6 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 7 Column: j
Customer Charges; Margin Credits; Transmission; Annual Formula True Up Estimates

Schedule Page: 310 Line No.: 8 Column: a
LP&L has two contracts. There is a partial contract as well as a bridge contract. The total load volume per the contracts is a total of 170 MV per month, as such we are not calculating average actual amounts for this counterparty.

Schedule Page: 310 Line No.: 9 Column: b
SPP Market Transactions

Schedule Page: 310 Line No.: 9 Column: j
Transmission and Trading Revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,689,142	2,290,065
5	(501) Fuel	219,139,010	303,338,421
6	(502) Steam Expenses	10,243,828	10,894,158
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	9,787,894	10,203,419
10	(506) Miscellaneous Steam Power Expenses	12,820,822	13,365,874
11	(507) Rents	5,834,149	6,556,090
12	(509) Allowances		122,490
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	260,514,845	346,770,517
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	986,115	1,419,933
16	(511) Maintenance of Structures	4,744,308	5,469,723
17	(512) Maintenance of Boiler Plant	13,981,017	16,202,910
18	(513) Maintenance of Electric Plant	11,092,566	10,402,049
19	(514) Maintenance of Miscellaneous Steam Plant	11,041,916	11,082,554
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	41,845,922	44,577,169
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	302,360,767	391,347,686
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	289,789	32,100
63	(547) Fuel	22,476,936	40,552,886
64	(548) Generation Expenses	270,697	575,073
65	(549) Miscellaneous Other Power Generation Expenses	2,631,348	347,615
66	(550) Rents	1,556,936	498,229
67	TOTAL Operation (Enter Total of lines 62 thru 66)	27,225,706	42,005,903
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	276,105	214,330
70	(552) Maintenance of Structures	383,900	405,846
71	(553) Maintenance of Generating and Electric Plant	1,215,461	1,537,201
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,416,371	248,064
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	4,291,837	2,405,441
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	31,517,543	44,411,344
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	397,486,583	479,246,323
77	(556) System Control and Load Dispatching	1,227,541	1,108,043
78	(557) Other Expenses	-4,207,249	11,792,804
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	394,506,875	492,147,170
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	728,385,185	927,906,200
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,299,034	9,363,000
84			
85	(561.1) Load Dispatch-Reliability	188	214,751
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	3,103,208	3,243,101
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,152,837	4,019,222
89	(561.5) Reliability, Planning and Standards Development	39,272	52
90	(561.6) Transmission Service Studies	66,328	-72,607
91	(561.7) Generation Interconnection Studies	43,198	-49,144
92	(561.8) Reliability, Planning and Standards Development Services	2,862,939	3,285,498
93	(562) Station Expenses	1,662,682	1,963,348
94	(563) Overhead Lines Expenses	662,806	850,039
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	170,784,179	165,000,832
97	(566) Miscellaneous Transmission Expenses	2,907,452	2,838,661
98	(567) Rents	2,187,682	2,059,747
99	TOTAL Operation (Enter Total of lines 83 thru 98)	197,771,805	192,716,500
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		25,020
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,610,872	1,956,421
108	(571) Maintenance of Overhead Lines	1,000,520	946,050
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,611,392	2,927,491
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	200,383,197	195,643,991

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	147,973	169,027
116	(575.2) Day-Ahead and Real-Time Market Facilitation	330,027	311,254
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	16,943	19,911
120	(575.6) Market Monitoring and Compliance	42,807	35,401
121	(575.7) Market Facilitation, Monitoring and Compliance Services	7,890,397	8,300,814
122	(575.8) Rents	64,528	37,079
123	Total Operation (Lines 115 thru 122)	8,492,675	8,873,486
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	8,492,675	8,873,486
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,183,021	2,556,619
135	(581) Load Dispatching	286,220	329,085
136	(582) Station Expenses	1,355,670	1,717,218
137	(583) Overhead Line Expenses	1,272,683	2,098,203
138	(584) Underground Line Expenses	423,783	-272,844
139	(585) Street Lighting and Signal System Expenses	566,001	211,147
140	(586) Meter Expenses	2,514,426	3,107,875
141	(587) Customer Installations Expenses	761,456	878,960
142	(588) Miscellaneous Expenses	10,164,613	15,844,820
143	(589) Rents	3,131,807	2,630,873
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,659,680	29,101,956
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	33,548	12,051
147	(591) Maintenance of Structures		6,274
148	(592) Maintenance of Station Equipment	825,140	892,474
149	(593) Maintenance of Overhead Lines	9,747,983	7,455,870
150	(594) Maintenance of Underground Lines	202,902	586,215
151	(595) Maintenance of Line Transformers		-856
152	(596) Maintenance of Street Lighting and Signal Systems	172,840	670,964
153	(597) Maintenance of Meters	6,023	14,607
154	(598) Maintenance of Miscellaneous Distribution Plant	20,368	
155	TOTAL Maintenance (Total of lines 146 thru 154)	11,008,804	9,637,599
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	35,668,484	38,739,555
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	29,909	19,140
160	(902) Meter Reading Expenses	4,737,186	4,693,900
161	(903) Customer Records and Collection Expenses	8,539,029	6,932,491
162	(904) Uncollectible Accounts	5,946,433	4,423,764
163	(905) Miscellaneous Customer Accounts Expenses		314,588
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	19,252,557	16,383,883

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	18,722,506	19,790,029
169	(909) Informational and Instructional Expenses	368,506	601,363
170	(910) Miscellaneous Customer Service and Informational Expenses	43,205	6,262
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	19,134,217	20,397,654
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	272,795	233,108
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	272,795	233,108
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	36,959,455	30,544,808
182	(921) Office Supplies and Expenses	20,389,704	18,871,416
183	(Less) (922) Administrative Expenses Transferred-Credit	18,655,445	17,374,866
184	(923) Outside Services Employed	7,892,539	10,387,950
185	(924) Property Insurance	3,304,198	3,403,516
186	(925) Injuries and Damages	9,010,326	5,364,869
187	(926) Employee Pensions and Benefits	29,772,262	34,419,385
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,828,159	9,883,923
190	(929) (Less) Duplicate Charges-Cr.	1,339,854	1,405,511
191	(930.1) General Advertising Expenses	1,381,970	1,258,364
192	(930.2) Miscellaneous General Expenses	1,132,816	1,237,523
193	(931) Rents	13,883,843	12,812,192
194	TOTAL Operation (Enter Total of lines 181 thru 193)	112,559,973	109,403,569
195	Maintenance		
196	(935) Maintenance of General Plant	112,313	195,450
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	112,672,286	109,599,019
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,124,261,396	1,317,776,896

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 5 Column: b

FERC 501 - Fuel includes $1,343,767.21 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 5 Column: c

FERC 501 - Fuel includes $1,446,310.21 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 12 Column: c

The amount of $122,490 includes $124,830 of NOx purchases, $23,521 amortization of previously deferred NOx allowance cost and $5,133 amortization of previously deferred SO2 cost (authorized in NMPRC Case No. 17-00255), offset by deferral of New Mexico share of 2018 NOx purchase of ($30,994).

Schedule Page: 320 Line No.: 76 Column: b

FERC 555 - Purchased Power includes $15,575 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 76 Column: c

FERC 555 - Purchased Power includes $42,670 of ancillary service cost reclassed to gen book trading cost.

Schedule Page: 320 Line No.: 78 Column: b

The total of this account includes deferred expenses related to Fuel and Renewable Energy Costs as follows:

Fuel	($10,584,998)
RECs and other renewable energy costs	$3,590,167

Schedule Page: 320 Line No.: 78 Column: c

The total of this account includes deferred expenses related to Fuel and Renewable Energy Costs as follows:

Fuel	$5,727,279
RECs and other renewable energy costs	$3,909,570

Schedule Page: 320 Line No.: 90 Column: c

Credit balance results because Pension, Insurance and Taxes on Company labor billed for performing the studies is booked to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is booked to Account No. 561.6

Schedule Page: 320 Line No.: 91 Column: c

Generation Interconnection Study Revenues exceeded cost for the period.

Schedule Page: 320 Line No.: 138 Column: c

Unnatural balance and offset accounts for First Credits are in FERC 594

Schedule Page: 320 Line No.: 187 Column: b

Texas PUC Docket No. 38147 authorized deferral of expense to Account No. 182.3
Docket 40824 authorized amortization of 12/31/12 deferred balance.
Docket No. 42004 extended the amortization period of the 12/31/12 balance; remaining balance of $3,025,000 as of 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2013 deferral of $3,468,975 over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2014 deferral of $196,032 through 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 43695 authorized revised amortization of total deferred pension and OPEB expense of $3,583,510 to be amortized over 24 months beginning 6/11/15.
Docket No. 45524 authorized revised amortization of the total deferred pension and OPEB expense of $1,841,525 to be amortized over 24 months beginning 7/1/16
Docket No. 47527 authorized revised amortization of the total deferred pension and OPEB expense of $(664,316) to be amortized over 24 months beginning 2/1/18

Pension and Benefit Expense	$28,913,970
Pension Tracker	1,190,450
Amortization	(332,158)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Pension and Benefit Expense as Reported	$29,772,262

Schedule Page: 320 Line No.: 187 Column: c

Texas PUC Docket No. 38147 authorized deferral of expense to Account No. 182.3
Docket 40824 authorized amortization of 12/31/12 deferred balance.
Docket No. 42004 extended the amortization period of the 12/31/12 balance; remaining balance of $3,025,000 as of 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2013 deferral of $3,468,975 over 36 months beginning 6/1/14.
Docket No. 42004 authorized amortization of the 2014 deferral of $196,032 through 5/31/14 to be amortized over 36 months beginning 6/1/14.
Docket No. 43695 authorized revised amortization of total deferred pension and OPEB expense of $3,583,510 to be amortized over 24 months beginning 6/11/15.
Docket No. 45524 authorized revised amortization of the total deferred pension and OPEB expense of $1,841,525 to be amortized over 24 months beginning 7/1/16
Docket No. 47527 authorized revised amortization of the total deferred pension and OPEB expense of $(664,316) to be amortized over 24 months beginning 2/1/18

Pension and Benefit Expense	$36,656,442
Pension Tracker	(1,469,509)
Amortization	(767,548)
Pension and Benefit Expense as Reported	$34,419,385

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Aeolus Wind, LLC	LU	QF			
2	Borger Energy Associates	RQ	PSA	227		
3	Caprock Wind LP	LU	Wind PSA			
4	Chaves County Solar, LLC	LU	Solar PSA			
5	Cirrus Wind I LLC	LU	QF			
6	Lea Power Partners	RQ	PSA	604		
7	Lubbock Power & Light	OS	SPSV3			
8	Lubbock Power & Light	RQ	PSA	19		
9	Lorenzo Wind LLC	LU	Wind PSA			
10	Mammoth Plains Wind Project Holdings,L	LU	Wind PSA			
11	Mesalands Community College LP	LU	QF			
12	National Windmill Project, Inc.	LU	QF			
13	Net Metering	OS	N/A			
14	Oneta Power LLC	RQ	PSA	83		
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Orion Engineered Carbons LLC	RQ	PSA			
2	Palo Duro Wind LLC	LU	Wind PSA			
3	Pantex Wind	LU	QF			
4	Pleasant Hills Wind Energy	LU	QF			
5	Ralls Wind Farm, LLC	LU	QF			
6	Roosevelt Wind Ranch LLC	LU	Wind PSA			
7	Roswell Solar, LLC	LU	Solar PSA			
8	San Juan Mesa Wind Project, LLC	LU	Wind PSA			
9	Southwest Power Pool	OS	SPSV3			
10	Spinning Spur Wind LLC	LU	Wind PSA			
11	Sun Edison Solar SPS LLC	LU	Solar PSA			
12	Suzlon Project VIII, LLC	LU	QF			
13	Texico Wind, LP	LU	Wind PSA			
14	Tokai Carbon CB Ltd	RQ	PSA	3		
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	West Texas A&M University	LU	QF			
2	Wildorado Wind LP	LU	Wind PSA			
3	Wildcat Ranch Wind Project LLC	LU	Wind PSA			
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
8,748				76,504		76,504	1
1,437,912			16,722,681	23,941,062		40,663,743	2
320,798				10,698,610		10,698,610	3
165,769				6,088,220	537,997	6,626,217	4
93,441				1,504,955	-23,113	1,481,842	5
3,374,517			48,215,999	44,534,616		92,750,615	6
425,240				11,844,356		11,844,356	7
			-69,960			-69,960	8
360,486				6,524,802	67,803	6,592,605	9
816,919				16,983,176	259,235	17,242,411	10
2,815				30,193	-549	29,644	11
274				3,833	-73	3,760	12
4,652				107,295		107,295	13
3,605			2,987,400	154,465		3,141,865	14
15,447,224			68,012,595	303,255,384	26,218,604	397,486,583	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
93,776				1,511,130		1,511,130	1
1,077,653				24,449,226	-863,508	23,585,718	2
13,987				74,945	-16,988	57,957	3
52,554				920,626	-21,407	899,219	4
23,388				421,611	-14,130	407,481	5
1,129,493				24,174,785	250,199	24,424,984	6
164,421				5,972,192	592,217	6,564,409	7
407,046				13,802,916		13,802,916	8
3,483,269				40,844,471	24,704,196	65,548,667	9
720,002				27,792,088	308,568	28,100,656	10
96,899				12,480,986		12,480,986	11
12,671				147,492	-5,336	142,156	12
1,348				63,726		63,726	13
27,796			156,475	212,498		368,973	14
15,447,224			68,012,595	303,255,384	26,218,604	397,486,583	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,380				101,276	-1,816	99,460	1
441,032				15,586,089		15,586,089	2
680,333				12,207,240	445,309	12,652,549	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
15,447,224			68,012,595	303,255,384	26,218,604	397,486,583	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 4 Column: l
Curtailment Adjustment

Schedule Page: 326 Line No.: 5 Column: l
SPP market charge pass through

Schedule Page: 326 Line No.: 9 Column: l
Curtailment Adjustment

Schedule Page: 326 Line No.: 10 Column: l
Curtailment Adjustment

Schedule Page: 326 Line No.: 11 Column: l
SPP market charge pass through

Schedule Page: 326 Line No.: 12 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 2 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 3 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 4 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 5 Column: l
SPP market charge pass through

Schedule Page: 326.1 Line No.: 6 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 7 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 9 Column: b
SPP market charge pass through

Schedule Page: 326.1 Line No.: 9 Column: l
SPP market charges and ASM revenue

Regulation & Frequency Response Service	$ (7,165,032)
Spinning Reserve Service	(6,169,067)
Supplemental Reserve Service	(122,104)
	$ (13,456,204)

Schedule Page: 326.1 Line No.: 10 Column: l
Curtailment Adjustment

Schedule Page: 326.1 Line No.: 12 Column: l
SPP market charge pass through

Schedule Page: 326.2 Line No.: 1 Column: l
SPP market charge pass through

Schedule Page: 326.2 Line No.: 3 Column: l
Curtailment Adjustment

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Southwest Power Pool	N/A	N/A	
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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23				
24				
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26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
SPP OATT	Various	Various		11,417,232	11,417,232	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
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						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**11,417,232**	**11,417,232**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
245,191,863		1,581,098	246,772,961	1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
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				26
				27
				28
				29
				30
				31
				32
				33
				34
245,191,863	**0**	**1,581,098**	**246,772,961**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: d

LFP, SFP, FNO, FNS, OS

Schedule Page: 328 Line No.: 1 Column: m

Radial Line Facilities & Meter Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Southwest Power Pool				167,031,599	3,205,327	518,975	170,755,901
2	Swisher	OS					17,510	17,510
3	NPEC	OS			9,686		1,082	10,768
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				167,041,285	3,205,327	537,567	170,784,179

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: b

FNS, LFP, SFP, OS

Schedule Page: 332 Line No.: 1 Column: g

Other Charges for Southwest Power Pool (SPP) include the following:

Direct Assignment Charges (Meter Readings, Radial Facilities, Distribution, Other)	185,979
SPP Annual Membership Fee	6,000
Direct Assigned Upgrade Charges per Z2 Tariff	326,996

$ 518,975

Schedule Page: 332 Line No.: 2 Column: g

Other Charges for Swisher Electric Cooperative include the following:

Wheeling Charge	15,950
Annual Equipment Rental Fee	1,560

$17,510

Schedule Page: 332 Line No.: 3 Column: g

Other Charges for North Plains Electric Cooperative (NPEC) include the following:

North Plains Monthly Customer Fee	1,082

$ 1,082

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	22,424
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Other	
7	Service Company Allocation of Other Expense	
8	Service Company Allocation of Shareholder Meetings	95,008
9	Shareholder Meetings	
10	Service Company Allocation of Consulting Expense	
11	Service Company Allocation of Director Fees and Exp	468,555
12	Director Fees and Exp	
13	Service Company Allocation of SEC Filing Expense	61,545
14	Service Company Allocaton of Industry Dues	485,284
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
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32		
33		
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36		
37		
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39		
40		
41		
42		
43		
44		
45		
46	TOTAL	1,132,816

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			24,927,385		24,927,385
2	Steam Production Plant	46,625,315	-64,617	440,765		47,001,463
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	21,388,094	371,984			21,760,078
7	Transmission Plant	67,437,197	782	2,327,168		69,765,147
8	Distribution Plant	36,553,012	309,692	166,689	-238,109	36,791,284
9	Regional Transmission and Market Operation					
10	General Plant	24,448,170	1,218	272,494		24,721,882
11	Common Plant-Electric					
12	TOTAL	196,451,788	619,059	28,134,501	-238,109	224,967,239

B. Basis for Amortization Charges

Column (d) line 12: Land and Water Rights are being amortized over the life of the asset.

Column (d) line 12: Leased Property improvements are being amortized over the life of the lease.

Column (d) line 12: Computer software is being amortized over its expected useful life.

Column (e) line 8: Contributions in Aid of Construction Gross-up recorded as a Regulatory Liability and amortized over 20 years, and thus appears as a credit to expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production-Coal						
13	310	1,563					
14	310	311			1.87		12.92
15	310	10,220			3.49		21.76
16	311	138,291		-7.76	2.59		21.15
17	312	797,402		-4.43	2.34		21.00
18	314	346,579		-4.50	2.16		22.74
19	315	50,274		-4.02	1.94		22.52
20	316	18,397		-6.46	2.11		19.37
21	317	1,652					
22	Subtotal Steam Prod-Cl	1,364,689					
23							
24	Steam Production-Gas						
25	310	2,793					
26	310	787					
27	310	1,331					
28	310	73					
29	311	104,405					
30	312	215,122					
31	314	169,722					
32	315	35,187					
33	316	14,105					
34	317	12,245					
35	Subtotal Steam Prod-G	555,770					
36							
37	Other Production						
38	340	188					
39	340	1					
40	341	37,269					
41	342	6,086					
42	343	54,838					
43	344	488,217					
44	345	41,613					
45	346	4,758					
46	347	8,145					
47	Subtotal Other Prod	641,115					
48							
49	Transmission						
50	350	8,743					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	350	154,585					
13	350	32					
14	352	111,074					
15	353	1,162,321					
16	354	8,193					
17	355	1,221,872					
18	356	460,888					
19	357	274					
20	358	490					
21	359	518					
22	359.1	25					
23	Subtotal Transmission	3,129,015					
24							
25	Distribution						
26	360	6,749					
27	360	10,816					
28	361	28,235					
29	362	296,681					
30	364	315,429					
31	365	277,943					
32	366	25,918					
33	367	46,792					
34	368	223,218					
35	369	47,895					
36	369	43,358					
37	370	67,834					
38	371	6,524					
39	373	30,364					
40	374	7,467					
41	Subtotal Distribution	1,435,223					
42							
43	General						
44	389	1,057					
45	389	46					
46	390	72,380					
47	390	4,233					
48	391	17,973					
49	391	77,273					
50	392	3,526					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	392	44,393					
13	392	8,690					
14	392	58,368					
15	393	431					
16	394	46,377					
17	395	11,060					
18	396	14,405					
19	397	63,695					
20	397	38,519					
21	397	52					
22	397	19,626					
23	398	2,784					
24	399.1	64					
25	Subtotal General	484,952					
26							
27	TOTAL	7,610,764					
28							
29							
30							
31							
32							
33							
34							
35							
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50							

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 1 Column: d

The Amortization of Limited Term Electric Plant within Account 404 includes the following:

Software $24,927,385

Schedule Page: 336 Line No.: 7 Column: b

Transmission Serving Production $ 616,046

Schedule Page: 336 Line No.: 12 Column: f

NOTE: Amounts footnoted are based upon FERC ONLY RATES.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited Term Electric Plant (Account 404) (d)	Total (f)
1	Intangible Plant	$ -	$ 24,962,762	$ 24,962,762
2	Steam Production Plant	48,980,592	613,730	49,594,322
3	Nuclear Production Plant			-
4	Hydraulic Production Plant-Conventional			-
5	Hydraulic Production Plant-Pumped Storage			-
6	Other Production Plant	24,034,925	-	24,034,925
7	Transmssion Plant	57,938,741	3,079,265	61,018,006
8	Distribution Plant	36,553,012	166,689	36,719,701
9	Regional Transmission and Market Operation			-
10	General Plant	23,363,936	272,429	23,636,365
11	Common Plant-Electric			-
12	Total	$ 190,871,206	$ 29,094,875	$ 219,966,081

B. Basis for Amortization Charges

Column (d) line 12: Land and Water Rights are being amortized over the life of the asset.

Column (d) line 12: Leased Property improvements are being amortized over the life of the lease.

Column (d) line 12: Computer software is being amortized over its expected

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

useful life.
Transmission Serving Production $ 574,530

The Amortization of Limited Term Electric Plant within Account 404 includes the following:
Software $ 24,962,762

NOTE: Amounts footnoted are based upon FERC ONLY RATES.

Schedule Page: 336 Line No.: 13 Column: a
310 Land Owned in Fee
Schedule Page: 336 Line No.: 14 Column: a
310.002 Land Rights
Schedule Page: 336 Line No.: 15 Column: a
310.003 Production Water Rights
Schedule Page: 336 Line No.: 25 Column: a
310 Land Owned in Fee
Schedule Page: 336 Line No.: 26 Column: a
310.002 Land Rights
Schedule Page: 336 Line No.: 27 Column: a
310.003 Production Water Rights
Schedule Page: 336 Line No.: 28 Column: a
310.004 Production Land Rights
Schedule Page: 336 Line No.: 38 Column: a
340 Other Production - Land Owned in Fee
Schedule Page: 336 Line No.: 39 Column: a
340 Other Production - Land Rights
Schedule Page: 336 Line No.: 50 Column: a
350 Transmission - Land Owned in Fee
Schedule Page: 336.1 Line No.: 12 Column: a
350 Transmission - Land Rights
Schedule Page: 336.1 Line No.: 13 Column: a
350 Transmission - Wind Rights
Schedule Page: 336.1 Line No.: 26 Column: a
360 Distribution - Land Owned in Fee
Schedule Page: 336.1 Line No.: 27 Column: a
360 Distribution - Land Rights
Schedule Page: 336.1 Line No.: 35 Column: a
369.1 Overhead Services
Schedule Page: 336.1 Line No.: 36 Column: a
369.2 Underground Services
Schedule Page: 336.1 Line No.: 44 Column: a
389 General - Land Owned in Fee
Schedule Page: 336.1 Line No.: 45 Column: a
389 General - Land Rights
Schedule Page: 336.1 Line No.: 46 Column: a
390 Structures and Improvements
Schedule Page: 336.1 Line No.: 47 Column: a
390.7 Remodeling Lease Facilities
Schedule Page: 336.1 Line No.: 48 Column: a
391 Office Furniture and Equipment
Schedule Page: 336.1 Line No.: 49 Column: a
391.4 Network Equipment
Schedule Page: 336.1 Line No.: 50 Column: a

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

392.1 Transportation Equipment - Automobiles

Schedule Page: 336.2 Line No.: 12 Column: a

392.2 Transportation Equipment - Light Trucks

Schedule Page: 336.2 Line No.: 13 Column: a

392.3 Transportation Equipment - Trailers

Schedule Page: 336.2 Line No.: 14 Column: a

392.4 Transportation Equipment - Heavy Trucks

Schedule Page: 336.2 Line No.: 18 Column: a

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	$ 7,712,870	$ 114,977,000
396 Power Operated Equipment	731,190	14,405,000
Total	$ 8,444,060	$ 129,382,000

A reserve deficiency true-up was conducted in November 2015, pursuant to the rate case order. The true-up was allocated to accounts 392 Transportation Equipment and 396 Power Operated Equipment.

Schedule Page: 336.2 Line No.: 19 Column: a

397 Communication Equipment

Schedule Page: 336.2 Line No.: 20 Column: a

397.1 Communication Equipment - Two Way

Schedule Page: 336.2 Line No.: 21 Column: a

397.2 Communication Equipment - AES

Schedule Page: 336.2 Line No.: 22 Column: a

397.3 Communication Equipment - EMS

Schedule Page: 336.2 Line No.: 27 Column: b

(1) Column (b) Computation:
Depreciable Plant Balances are an average of the beginning and ending plant balance for the year.

(2) Columns (c) through (g):
2019 changes: Steam Production-Coal rates have been updated due to approved rates from the settlement of FERC Docket No. ER18-228 regarding the depreciable life of the Tolk plant. The order, issued on April 4, 2019, became effective retroactive to January 1, 2018.

2018 changes: Steam Production-Coal rates were updated in the 2018 FERC Form 1 due to approved rates from the SPS PUC Texas Case 47527 that became effective 1/1/2018 related to the Tolk plant.

No other changes to the underlying factors presented in columns (c) through (g) have occurred since filing the 2016 FERC Form 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Public Utilies Commission of Texas:				
2	Gross Receipts Assessment	1,348,180		1,348,180	
3	Docs. 45524 & 46328 - 2016 TX RC		1,526,407	1,526,407	1,402,374
4	Docs. 46025 & 47588 - 2016 TX Fuel Rec				625,699
5	Docs. 46877 & 47588 - 2017 TX TCRF				179,810
6	Docs. 47035 & 47588 - 2017 TX Surcharge				19,017
7	Docs. 47527 & 47588 - 2017 TX RC		837,649	837,649	1,450,000
8	Doc 48973 - 2018 TX Fuel Reconciliation				331,049
9	Doc 49831 - 2019 TX RC				188,068
10	Doc. 48847 - ITS Fuel Factor Formulas		-74,836	-74,836	
11	Doc. 49384 SPS PCF Rider		46,998	46,998	60,595
12	Doc. 49616 TX Fuel Formula				5,064
13	Miscellaneous items < $25K		20,388	20,388	1,989
14					
15	New Mexico Public Regulation Commission				
16	Assessment Charges	2,151,479		2,151,479	
17					
18					
19	Case 17-00255-UT - 2017 NM RC		928,994	928,994	1,150,897
20	Case No. S-1-SC-37308		130,842	130,842	96,670
21	Case S-1-SC-36466 - 2017 NM SCC		846	846	451
22	Case 19-00170-UT - 2019 NM RC				3,764
23	Case 18-00308 - Solar*Connect		89,681	89,681	
24	Case 18-00329 - Plant X & Cunningham Reti		55,457	55,457	
25	Case No. 19-00211		45,584	45,584	
26	Miscellaneous items < $25K		21,554	21,554	
27					
28	Federal Energy Regulatory Commission:				
29	ER18-228 - Production Formula Rate Change		25,525	25,525	
30					
31	ER18-2358 - GridLiance Transmission Rate Case		754,248	754,248	
32					
33	ER19-404 -Transmission Formula Template Change		191,529	191,529	
34					
35	ER19-675 - Distribution Formula Rate		192,404	192,404	
36					
37	EL18-9-000 Notice of Complaint, Xcel Energy		64,755	64,755	
38	vs Southwest Power Pool				
39	EL19-62-000 Notice of Complaint; City		38,835	38,835	
40	Utilities of Springfield, Missouri vs SPP				
41	ER19-1613 Hale Wind Project		115,260	115,260	
42					
43	ER20-277 -Production Depreciation Rates Update		175,000	175,000	
44					
45	QM19-4-000 Application to Terminate		116,116	116,116	
46	TOTAL	3,499,659	5,328,500	8,828,159	5,515,447

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Mandatory Purchase Obligation				
2	Miscellaneous items < $25K		10,062	10,062	
3					
4	OTHER				
5	Mandated Regulatory Notices		6,929	6,929	
6	Miscellaneous Items < $25,000		8,273	8,273	
7					
8					
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12					
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40					
41					
42					
43					
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45					
46	TOTAL	3,499,659	5,328,500	8,828,159	5,515,447

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	1,348,180					2
Electric	928	1,526,407		186	1,526,407	-124,033	3
Electric			-625,699	186			4
Electric			-179,810	186			5
Electric			-19,017	186			6
Electric	928	837,649	840,588	186	837,649	1,452,939	7
Electric			1,112,670			1,443,719	8
Electric			1,489,035			1,677,103	9
Electric	928	-74,836					10
Electric	928	46,998	145,904		46,998	159,501	11
Electric			396,374			401,438	12
Electric	928	20,388	34,087			36,076	13
							14
							15
Electric	928	2,151,479					16
							17
							18
Electric	928	928,994	25	186	928,994	221,928	19
Electric	928	130,842	34,173	186	130,842		20
Electric	928	846	395	186	846		21
Electric	928		1,254,913	186		1,258,677	22
Electric	928	89,681					23
Electric	928	55,457					24
Electric	928	45,584					25
Electric	928	21,554					26
							27
							28
Electric	928	25,525					29
							30
Electric	928	754,248					31
							32
Electric	928	191,529					33
							34
Electric	928	192,404					35
							36
Electric	928	64,755					37
							38
Electric	928	38,835					39
							40
Electric	928	115,260					41
							42
Electric	928	175,000					43
							44
Electric	928	116,116					45
		8,828,158	4,483,638		3,471,736	6,527,348	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	10,062					2
							3
							4
Electric	928	6,929					5
Electric	928	8,272					6
							7
							8
							9
							10
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							45
		8,828,158	4,483,638		3,471,736	6,527,348	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute
2		
3	B(2)	Edision Electric Institute
4		
5	B(5)	Total
6		
7		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	111,733	Various	111,733		1
					2
	313,428	Various	313,428		3
					4
	425,161		425,161		5
					6
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					8
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 352 Line No.: 1 Column: e

Accounts charged:

501	300
921	0
923	4,569
930.2	106,864
	$111,733

Schedule Page: 352 Line No.: 3 Column: e

Accounts charged:

426.1	$4,388
426.4	42,817
908	293
921	6,488
930.2	259,442
	$313,428

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	29,154,219		
4	Transmission	12,392,130		
5	Regional Market	521,240		
6	Distribution	13,425,366		
7	Customer Accounts	6,581,544		
8	Customer Service and Informational	1,878,228		
9	Sales	265,753		
10	Administrative and General	36,959,455		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	101,177,935		
12	Maintenance			
13	Production	19,044,685		
14	Transmission	826,972		
15	Regional Market			
16	Distribution	4,825,943		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	24,697,600		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	48,198,904		
21	Transmission (Enter Total of lines 4 and 14)	13,219,102		
22	Regional Market (Enter Total of Lines 5 and 15)	521,240		
23	Distribution (Enter Total of lines 6 and 16)	18,251,309		
24	Customer Accounts (Transcribe from line 7)	6,581,544		
25	Customer Service and Informational (Transcribe from line 8)	1,878,228		
26	Sales (Transcribe from line 9)	265,753		
27	Administrative and General (Enter Total of lines 10 and 17)	36,959,455		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	125,875,535	1,999,807	127,875,342
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	125,875,535	1,999,807	127,875,342
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	38,441,658	21,221,347	59,663,005
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	38,441,658	21,221,347	59,663,005
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,352,037	1,850,459	5,202,496
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,352,037	1,850,459	5,202,496
77	Other Accounts (Specify, provide details in footnote):			
78	Regulatory Assets (Acct. No. 182.3)	889,247	7,503	896,750
79	Misc. Deferred Debits (Acct. No. 186)	42,195	321	42,516
80	Accounts Payable (Acct. No. 232)	16		16
81	Non-utility (Accts. No. 416-417.1)	23,983	368	24,351
82	Misc. Income and Deductions (Accts. No. 426.1-426.5)	152,206	1,613	153,819
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,107,647	9,805	1,117,452
96	TOTAL SALARIES AND WAGES	168,776,877	25,081,418	193,858,295

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	23,383,340	45,518,350	65,800,383	90,323,513
3	Net Sales (Account 447)	(12,179,659)	(19,712,730)	(32,267,125)	(43,319,316)
4	Transmission Rights	(6,483,487)	(19,693,124)	(24,022,205)	(33,302,467)
5	Ancillary Services	(2,031,345)	(3,114,848)	(3,865,862)	(6,119,616)
6	Other Items (list separately)				
7	Admin Fees				
8					
9					
10					
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44					
45					
46	TOTAL	2,688,849	2,997,648	5,645,191	7,582,114

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			4,787,856			1,247,451
2	Reactive Supply and Voltage			82,502			97,520
3	Regulation and Frequency Response			4,076,565			7,356,579
4	Energy Imbalance						
5	Operating Reserve - Spinning			3,567,582			6,169,067
6	Operating Reserve - Supplement			658,281			122,104
7	Other						
8	Total (Lines 1 thru 7)			13,172,786			14,992,721

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: b

Volume is not available for lines 1 through 7.

Schedule Page: 398 Line No.: 1 Column: c

Volume is nto available for lines 1 through 7.

Schedule Page: 398 Line No.: 1 Column: d

Sch 1 Charges	635,019
SPP Administrative Fees - SSC&D	4,152,837

Total 'Scheduling, System Control & Dispatch' 4,787,856

Schedule Page: 398 Line No.: 1 Column: e

Volume is not available for lines 1 through 7.

Schedule Page: 398 Line No.: 1 Column: f

Volume is not available for lines 1 through 7.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,208	1	1900	2,904	1,304				
2	February	4,280	8	800	2,903	1,377				
3	March	4,346	4	1000	2,959	1,387				
4	Total for Quarter 1				8,766	4,068				
5	April	4,358	9	1800	2,760	1,598				
6	May	4,387	23	1600	2,805	1,582				
7	June	5,446	28	1800	3,412	2,034				
8	Total for Quarter 2				8,977	5,214				
9	July	6,132	19	1700	3,679	2,453				
10	August	6,205	26	1700	3,677	2,528				
11	September	5,776	3	1700	3,498	2,278				
12	Total for Quarter 3				10,854	7,259				
13	October	4,271	31	800	2,935	1,336				
14	November	4,322	12	800	2,937	1,385				
15	December	4,334	17	800	2,972	1,362				
16	Total for Quarter 4				8,844	4,083				
17	Total Year to Date/Year				37,441	20,624				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	21,027,060
3	Steam	11,798,151			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	3,651,254
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,136,276
7	Other	3,139,974			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	14,938,125	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	17,278
10	Purchases	15,447,224	27	Total Energy Losses	553,481
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	30,385,349
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	11,417,232			
17	Delivered	11,417,232			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	30,385,349			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Southwestern Public Service

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,435,012	199,943	3,614	1	19:00
30	February	2,234,827	268,839	3,638	8	8:00
31	March	2,443,538	326,752	3,727	4	10:00
32	April	2,224,683	218,526	3,471	9	18:00
33	May	2,289,778	203,546	3,607	31	18:00
34	June	2,432,063	364,633	3,944	28	18:00
35	July	2,846,982	466,011	4,223	19	17:00
36	August	3,034,917	622,091	4,261	5	17:00
37	September	2,612,498	448,420	4,146	3	17:00
38	October	2,399,886	526,140	3,430	31	8:00
39	November	2,441,048	492,700	3,413	12	8:00
40	December	2,990,117	998,675	3,458	18	8:00
41	TOTAL	30,385,349	5,136,276			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 401   Line No.: 14   Column: b

SPS has not found any FERC authority indicating the Inadvertent Energy is considered an exchange; therefore, Inadvertent Energy is not included in the exchange values reported on this page.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Quay County* (b)	Plant Name: *Plant X* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Outside Boiler
3	Year Originally Constructed	2013	1952
4	Year Last Unit was Installed	2013	1964
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	27.00	434.40
6	Net Peak Demand on Plant - MW (60 minutes)	20	351
7	Plant Hours Connected to Load	21	7286
8	Net Continuous Plant Capability (Megawatts)	23	411
9	When Not Limited by Condenser Water	23	411
10	When Limited by Condenser Water	17	411
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	231100	865534000
13	Cost of Plant: Land and Land Rights	103888	1752767
14	Structures and Improvements	916182	13762179
15	Equipment Costs	25551031	103622929
16	Asset Retirement Costs	0	-3707145
17	Total Cost	26571101	115430730
18	Cost per KW of Installed Capacity (line 17/5) Including	984.1149	265.7245
19	Production Expenses: Oper, Supv, & Engr	1008	272642
20	Fuel	83309	12492434
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	680341
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	10603	759575
26	Misc Steam (or Nuclear) Power Expenses	11702	1223385
27	Rents	4384	434385
28	Allowances	0	0
29	Maintenance Supervision and Engineering	1713	27807
30	Maintenance of Structures	2894	1100844
31	Maintenance of Boiler (or reactor) Plant	0	1698810
32	Maintenance of Electric Plant	95247	2533421
33	Maintenance of Misc Steam (or Nuclear) Plant	21333	1281890
34	Total Production Expenses	232193	22505534
35	Expenses per Net KWh	1.0047	0.0260

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil			Gas	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Bbls			Mcf	Bbls	
38	Quantity (Units) of Fuel Burned	1550	0	0	10031212	551	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	136236	0	0	1025	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	53.760	0.000	0.000	1.230	3.180	0.000
41	Average Cost of Fuel per Unit Burned	53.760	0.000	0.000	1.240	3.180	0.000
42	Average Cost of Fuel Burned per Million BTU	18.790	0.000	0.000	1.210	1.110	1.210
43	Average Cost of Fuel Burned per KWh Net Gen	0.360	0.000	0.000	0.000	0.000	0.010
44	Average BTU per KWh Net Generation	19181.238	0.000	0.000	0.000	0.000	11882.768

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Nichols Station* (b)			Plant Name: *Harrington* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Outside Boiler		
3	Year Originally Constructed	1960			1976		
4	Year Last Unit was Installed	1968			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	474.77			1080.00		
6	Net Peak Demand on Plant - MW (60 minutes)	469			1025		
7	Plant Hours Connected to Load	7669			8285		
8	Net Continuous Plant Capability (Megawatts)	457			1018		
9	When Not Limited by Condenser Water	457			1018		
10	When Limited by Condenser Water	457			1018		
11	Average Number of Employees	0			137		
12	Net Generation, Exclusive of Plant Use - KWh	1163100720			3735218000		
13	Cost of Plant: Land and Land Rights	818610			1231654		
14	Structures and Improvements	57201975			49733397		
15	Equipment Costs	115996570			542225324		
16	Asset Retirement Costs	-3190334			-73099		
17	Total Cost	170826821			593117276		
18	Cost per KW of Installed Capacity (line 17/5) Including	359.8096			549.1827		
19	Production Expenses: Oper, Supv, & Engr	119222			1000054		
20	Fuel	15876254			82562995		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	400164			3859905		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2288499			2566083		
26	Misc Steam (or Nuclear) Power Expenses	1542338			4024633		
27	Rents	497604			2092513		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	155996			233758		
30	Maintenance of Structures	352116			779657		
31	Maintenance of Boiler (or reactor) Plant	1579653			5368709		
32	Maintenance of Electric Plant	1941394			2550535		
33	Maintenance of Misc Steam (or Nuclear) Plant	1027691			3374638		
34	Total Production Expenses	25780931			108413480		
35	Expenses per Net KWh	0.0222			0.0290		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Coal	Gas	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Tons	Mcf	
38	Quantity (Units) of Fuel Burned	13681935	0	0	2214953	69204	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1035	0	0	1014	8893	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	1.150	0.000	0.000	36.670	10.750	0.000
41	Average Cost of Fuel per Unit Burned	1.160	0.000	0.000	36.720	18.420	0.000
42	Average Cost of Fuel Burned per Million BTU	1.130	0.000	0.000	2.070	2.070	2.070
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.000	0.020
44	Average BTU per KWh Net Generation	12113.178	0.000	0.000	0.000	0.000	10697.411

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Maddox Gas* (b)			Plant Name: *Cunningham Gas* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed	1976			1998		
4	Year Last Unit was Installed	1983			1998		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	98.35			253.80		
6	Net Peak Demand on Plant - MW (60 minutes)	67			218		
7	Plant Hours Connected to Load	4991			6720		
8	Net Continuous Plant Capability (Megawatts)	63			209		
9	When Not Limited by Condenser Water	63			209		
10	When Limited by Condenser Water	61			196		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	307811000			828966000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	1624629			588074		
15	Equipment Costs	18018666			82983456		
16	Asset Retirement Costs	0			0		
17	Total Cost	19643295			83571530		
18	Cost per KW of Installed Capacity (line 17/5) Including	199.7285			329.2810		
19	Production Expenses: Oper, Supv, & Engr	19329			52405		
20	Fuel	3855553			10426691		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	108036			140672		
26	Misc Steam (or Nuclear) Power Expenses	66684			222719		
27	Rents	84060			227910		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	32838			125082		
30	Maintenance of Structures	36848			247321		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	179194			281802		
33	Maintenance of Misc Steam (or Nuclear) Plant	14160			196025		
34	Total Production Expenses	4396702			11920627		
35	Expenses per Net KWh	0.0143			0.0144		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Mcf		
38	Quantity (Units) of Fuel Burned	3881620	0	0	9130942	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1022	0	0	1046	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.990	0.000	0.000	1.140	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.990	0.000	0.000	1.140	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.970	0.000	0.000	1.090	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.010	0.000	0.000
44	Average BTU per KWh Net Generation	12881.778	0.000	0.000	11516.330	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Tolk* (d)			Plant Name: *Jones Station* (e)			Plant Name: *Moore County* (f)			Line No.
		Steam			Steam			Steam	1
		Outside Boiler			Conventional			Outside Boiler	2
		1982			1971			1938	3
		1985			1974			1954	4
		1135.80			495.00			0.00	5
		1058			487			0	6
		7939			8038			0	7
		1067			486			0	8
		1067			486			0	9
		1067			486			0	10
		104			34			0	11
		2741754000			1832880000			0	12
		10862393			2274924			0	13
		89923855			16480673			0	14
		679174132			123675522			0	15
		31840341			2515362			0	16
		811800721			144946481			0	17
		714.7391			292.8212			0	18
		644685			532688			11	19
		66461577			24451305			13	20
		0			0			0	21
		1839798			1441710			1312	22
		0			0			0	23
		0			0			0	24
		1502784			1886708			0	25
		3260257			1550498			1052	26
		1634137			684430			47	27
		0			0			0	28
		158937			305847			0	29
		1496511			529071			0	30
		2575525			1418491			8	31
		1495062			1894082			0	32
		3579341			765583			8	33
		84648614			35460413			2451	34
		0.0309			0.0193			0.0000	35
Coal	Gas	Composite	Gas	Oil	Composite	Gas			36
Tons	Mcf		Mcf	Bbls		Mcf			37
1602475	371250	0	19373685	89	0	0	0	0	38
8883	1017	0	1025	0	0	0	0	0	39
40.910	1.190	0.000	1.250	42.140	0.000	0.000	0.000	0.000	40
41.150	1.190	0.000	1.270	42.140	0.000	0.000	0.000	0.000	41
2.320	1.170	2.300	1.230	14.750	1.230	0.000	0.000	0.000	42
0.000	0.000	0.020	0.000	0.000	0.010	0.000	0.000	0.000	43
0.000	0.000	10522.802	0.000	0.000	10837.581	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Carlsbad* (d)			Plant Name: *Cunningham Steam* (e)			Plant Name: *Maddox Steam* (f)			Line No.
Gas Turbine			Steam			Steam			1
			Outside Boiler			Outside Boiler			2
1977			1957			1967			3
1977			1965			1983			4
0.00			265.40			113.64			5
0			250			119			6
0			7432			7042			7
0			251			112			8
0			251			112			9
0			251			112			10
0			49			0			11
0			878871000			580793000			12
0			61235			25991			13
0			12669872			4913960			14
0			59990820			41853586			15
0			36284			-567704			16
0			72758211			46225833			17
0			274.1455			406.7743			18
3			72344			47496			19
0			10162041			7049082			20
0			0			0			21
0			1424657			595941			22
0			0			0			23
0			0			0			24
0			390538			393707			25
442			801340			417319			26
41			297880			193153			27
0			0			0			28
31			98377			5393			29
75			327502			158607			30
0			996432			323736			31
4			501868			159154			32
2			348151			663676			33
598			15421130			10007264			34
0.0000			0.0175			0.0172			35
Gas			Gas			Gas			36
Mcf			Mcf			Mcf			37
0	0	0	9232554	0	0	5996418	0	0	38
0	0	0	1027	0	0	1026	0	0	39
0.000	0.000	0.000	1.090	0.000	0.000	1.170	0.000	0.000	40
0.000	0.000	0.000	1.090	0.000	0.000	1.180	0.000	0.000	41
0.000	0.000	0.000	1.060	0.000	0.000	1.150	0.000	0.000	42
0.000	0.000	0.000	0.010	0.000	0.000	0.010	0.000	0.000	43
0.000	0.000	0.000	10787.722	0.000	0.000	10592.427	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Jones Station Gas* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Gas Turbine			1
			2
2011			3
2013			4
365.40	0.00	0.00	5
399	0	0	6
2786	0	0	7
366	0	0	8
366	0	0	9
336	0	0	10
0	0	0	11
728369000	0	0	12
0	0	0	13
11	0	0	14
155	0	0	15
0	0	0	16
166	0	0	17
0.0005	0	0	18
40906	0	0	19
8194692	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
7127	0	0	25
81903	0	0	26
177898	0	0	27
0	0	0	28
73245	0	0	29
96762	0	0	30
0	0	0	31
602273	0	0	32
29972	0	0	33
9304778	0	0	34
0.0128	0.0000	0.0000	35

									Line No.
Gas									36
Mcf									37
7198991	0	0	0	0	0	0	0	0	38
1027	0	0	0	0	0	0	0	0	39
1.140	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
1.140	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
1.110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.010	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
10149.419	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
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			8
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			10
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			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Wind Turbine:					
2	Hale Wind Farm	2019	478.00		1,274,596,722	691,791,465
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,447,262	3,490,938		2,292,658	Wind		2
						3
						4
						5
						6
						7
						8
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						10
						11
						12
						13
						14
						15
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						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(J26-KS;01) CARPENTER	HITCHLAND	345.00	345.00	H-FRAME	12.09		1
2	(J26-OK;01) CARPENTER	HITCHLAND	345.00	345.00	H-FRAME	38.14		1
3	(J26-TX;01) CARPENTER	HITCHLAND	345.00	345.00	H-FRAME	0.47		1
4	(J25;01) CARPENTER	FINNEY SW STA	345.00	345.00	H-FRAME	67.29		1
5	(J23;01) KIOWA	ROADRUNNER	345.00	345.00	H-FRAME	40.31		1
6	(J22;01) CHINA DRAW	NORTH LOVING	345.00	345.00	H-FRAME	18.11		1
7	(J21;01) KIOWA	NORTH LOVING	345.00	345.00	H-FRAME	21.89		1
8	(J20;01) HOBBS	KIOWA	345.00	345.00	H-FRAME	47.04		1
9			345.00	345.00	SINGLE POLE	0.81		1
10	(J18-NM;01) HOBBS	YOAKUM CO INTG	345.00	345.00	H-FRAME	36.41		1
11	(J18-TX;01) HOBBS	YOAKUM CO INTG	345.00	345.00	H-FRAME	25.37		1
12	(J15-NM;01) CROSSROADS	TOLK STA	345.00	345.00	H-FRAME	20.04		1
13	(J15-TX;01) CROSSROADS	TOLK STA	345.00	345.00	H-FRAME	31.79		1
14	(J14;01) CROSSROADS	EDDY CO INTG	345.00	345.00	H-FRAME	106.05		1
15	(J13-OK;02) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE		29.03	1
16	(J13-TX;02) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE		0.28	1
17	(J12-OK;01) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE	29.03		1
18	(J12-TX;01) HITCHLAND	OKPS (BEAVER CO)	345.00	345.00	SINGLE POLE	0.28		1
19	(J11-OK;01) BORDER	TUCO	345.00	345.00	SINGLE POLE	6.21		1
20	(J11-TX;01) BORDER	TUCO	345.00	345.00	3 POLE	0.87		1
21			345.00	345.00	H-FRAME	19.45		1
22			345.00	345.00	SINGLE POLE	174.83		1
23	(J06;01) HITCHLAND	POTTER CO SW STA	345.00	345.00	H-FRAME	102.59		1
24	(J05-KS;01) FINNEY SW STA	LAMAR 345KV SW STA	345.00	345.00	H-FRAME	78.76		1
25	(J04;01) FINNEY SW STA	HOLCOMB POWER PLANT	345.00	345.00	H-FRAME	0.75		1
26	(J01;01) OKLAUNION /	TUCO	345.00	345.00	H-FRAME	160.31	0.19	1
27	(R12;01) AMOCO WASSON	MAHONEY	230.00	230.00	K-FRAME	3.90		1
28	(R11;01) BRU	MAHONEY	230.00	230.00	K-FRAME	2.68		1
29	(R10-NM;01) HOBBS	INK BASIN	230.00	230.00	H-FRAME	23.11		1
30	(R10-TX;01) HOBBS	INK BASIN	230.00	230.00	H-FRAME	7.58		1
31	(R07;01) INK BASIN	YOAKUM CO INTG	230.00	230.00	H-FRAME	17.40	0.29	1
32	(R06;01) NEEDMORE	YOAKUM CO INTG	230.00	230.00	H-FRAME	13.91		1
33			230.00	230.00	K-FRAME	59.23		1
34			230.00	230.00	SPECIAL	1.12		1
35	(R05;01) NEEDMORE	TOLK STA	230.00	230.00	K-FRAME	13.67		1
36					TOTAL	7,155.62	594.81	129

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(R04-NM;01) ANDREWS CO.	HOBBS GENERATING	230.00	345.00	H-FRAME	0.47		1
2			230.00	345.00	H-FRAME	22.73		1
3	(R04-TX;01) ANDREWS CO.	HOBBS GENERATING	230.00	345.00	H-FRAME	7.69		1
4	(K99;01) CARLISLE	WOLFFORTH INTG	230.00	230.00	SINGLE POLE	13.04		1
5	(K98;01) CHANNING	XIT	230.00	230.00	SINGLE POLE	32.37		1
6	(K97;01) CHANNING	POTTER CO SW STA	230.00	230.00	SINGLE POLE	41.79		1
7	(K94;01) CIRRUS	GRASSLAND INTG	230.00	345.00	H-FRAME	1.67		1
8			230.00	345.00	SINGLE POLE	8.42		1
9	(K92;01) CUNNINGHAM	HOBBS GENERATING	230.00	230.00	H-FRAME	3.02		1
10	(K91;01) NEWHART	PLANT X	230.00	230.00	H-FRAME		1.27	1
11			230.00	230.00	SINGLE POLE	38.50		1
12	(K90;01) NEWHART	POTTER CO SW STA	230.00	230.00	H-FRAME	67.64		1
13	(K88;1) NEWHART	SWISHER CO INTG	230.00	230.00	SINGLE POLE	21.31		1
14	(K87;01) AMARILLO SOUTH	RANDALL CO	230.00	230.00	SINGLE POLE	8.36		1
15	(K86;01) HARRINGTON STA	ROLLING HILLS	230.00	230.00	H-FRAME	5.32	0.14	1
16	(K85;01) POTTER CO SW	ROLLING HILLS	230.00	230.00	H-FRAME	4.85		1
17			230.00	230.00	SINGLE POLE	1.15		1
18	(K84;01) PLEASANT HILL	ROOSEVELT CO INTG	230.00	230.00	SINGLE POLE	19.54		1
19	(K83;01) OASIS	PLEASANT HILL	230.00	230.00	H-FRAME	7.20		1
20			230.00	230.00	SINGLE POLE	21.35		1
21	(K82;01) BRU	OXY BENNETT RANCH	230.00	230.00	3 POLE	0.10		1
22	(K79-TX;01) BRU	YOAKUM CO INTG	230.00	230.00	H-FRAME	1.75		1
23			230.00	230.00	K-FRAME	3.60		1
24	(K76;01) HITCHLAND	OCHILTREE SUB	230.00	230.00	SINGLE POLE	38.14		1
25	(K75;01) HITCHLAND	MOORE CO	230.00	230.00	H-FRAME	62.52	0.18	1
26	(K74-OK;01) SWEETWATER	WHEELER CO.	230.00	230.00	H-FRAME	0.24		1
27	(K74-TX;01) SWEETWATER	WHEELER CO.	230.00	230.00	H-FRAME	13.96		1
28	(K73;01) GRAPEVINE INTG	WHEELER CO.	230.00	230.00	H-FRAME	36.87		1
29	(K69;01) MUSTANG INTG	SEMINOLE INTG	230.00	230.00	SINGLE POLE	18.07		1
30	(K68;01) PECOS	SEVEN RIVERS	230.00	230.00	H-FRAME	19.04		1
31			230.00	230.00	SINGLE POLE	1.64		1
32	(K67;01) PECOS	POTASH JUNCTION	230.00	230.00	H-FRAME	14.64		1
33	(K66;01) CHAVES CO	SAN JUAN MESA	230.00	230.00	H-FRAME	0.57		1
34			230.00	230.00	SINGLE POLE	51.16		1
35	(K65;01) OASIS	SAN JUAN MESA	230.00	230.00	H-FRAME	46.62		1
36					TOTAL	7,155.62	594.81	129

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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	(K63;01) AMARILLO SOUTH	SWISHER CO INTG	230.00	230.00	H-FRAME	49.09	0.53	1
2			230.00	230.00	K-FRAME		5.25	1
3			230.00	230.00	SINGLE POLE	0.99		1
4	(K62;01) AMARILLO SOUTH	NICHOLS STA	230.00	230.00	K-FRAME	9.13	10.50	1
5	(K60;01) EDDY CO INTG	SEVEN RIVERS	230.00	230.00	H-FRAME	24.34		1
6	(K59;01) BUSHLAND	POTTER CO SW STA	230.00	230.00	H-FRAME	0.95		1
7			230.00	230.00	K-FRAME	15.17	0.16	1
8			230.00	230.00	SINGLE POLE		1.15	1
9	(K56;01) MUSTANG INTG	YOAKUM CO INTG	230.00	230.00	H-FRAME	12.97		1
10			230.00	230.00	SINGLE POLE	0.90		1
11	(K55;01) AMOCO WASSON	MUSTANG INTG	230.00	230.00	H-FRAME	3.53		1
12	(K53;01) GRAPEVINE INTG	NICHOLS STA	230.00	230.00	K-FRAME	52.76		1
13	(K52;01) CUNNINGHAM	POTASH JUNCTION	230.00	230.00	H-FRAME	39.88		1
14	(K51;01) OASIS	ROOSEVELT CO INTG	230.00	230.00	H-FRAME	2.52		1
15			230.00	230.00	K-FRAME	7.16		1
16	(K47;01) GRASSLAND INTG	JONES PLANT	230.00	345.00	K-FRAME	26.72		1
17	(K46;01) PLANT X	SUNDOWN SW. STA.	230.00	230.00	H-FRAME		3.09	1
18			230.00	230.00	K-FRAME	45.15		1
19	(K45;02) PLANT X	TOLK STA	230.00	230.00	K-FRAME	9.83	0.28	1
20	(K44;01) EAST PLANT	HARRINGTON STA	230.00	230.00	SINGLE POLE	6.95	0.11	1
21	(K43;01) HARRINGTON STA	PRINGLE	230.00	230.00	K-FRAME	59.20		1
22	(K42;01) TOLK STA	TUCO	230.00	230.00	H-FRAME	4.61		1
23			230.00	230.00	K-FRAME	49.75		1
24	(K39;01) CARLISLE	MCDONALD (LP&L)	230.00	230.00	2 POLE	0.14	0.04	1
25	(K38;01) CHAVES CO	EDDY CO INTG	230.00	230.00	H-FRAME	2.73		1
26			230.00	230.00	K-FRAME	49.91		1
27	(K37;01) LAMB CO INTG	TOLK STA	230.00	230.00	K-FRAME	35.09		1
28	(K34;01) AMOCO	AMOCO SW. STA.	230.00	230.00	Unknown	0.03		1
29	(K33;01) AMOCO SW. STA.	YOAKUM CO INTG	230.00	230.00	H-FRAME	36.96		1
30	(K32;01) HARRINGTON STA	POTTER CO SW STA	230.00	230.00	K-FRAME	11.08	0.13	1
31	(K31;01) MOORE CO	POTTER CO SW STA	230.00	230.00	K-FRAME	47.90		1
32	(K30-NM;02) ROOSEVELT	TOLK STA	230.00	230.00	K-FRAME	9.59		1
33	(K30-TX;02) ROOSEVELT CO	TOLK STA	230.00	230.00	H-FRAME	8.35		1
34			230.00	230.00	K-FRAME	22.06		1
35	(K27;01) PLANT X	TOLK STA	230.00	230.00	K-FRAME	9.64		1
36					TOTAL	7,155.62	594.81	129

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(K24;01) CARLISLE	TUCO	230.00	230.00	H-FRAME	1.55		1
2			230.00	230.00	K-FRAME	25.60		1
3	(K23;01) CUNNINGHAM	EDDY CO INTG	230.00	230.00	K-FRAME	58.81		1
4	(K21;01) DEAF SMITH	PLANT X	230.00	230.00	H-FRAME	2.72		1
5			230.00	230.00	K-FRAME	44.15		1
6	(K19;01) HARRINGTON STA	RANDALL CO	230.00	230.00	K-FRAME	10.14	0.16	1
7			230.00	230.00	Unknown	1.34		1
8	(K18-NM;01) ROOSEVELT	TOLK STA	230.00	230.00	K-FRAME	11.23		1
9	(K18-TX;01) ROOSEVELT CO	TOLK STA	230.00	230.00	K-FRAME	28.03	0.02	1
10	(K17;02) HARRINGTON STA	NICHOLS STA	230.00	230.00	K-FRAME	0.95	0.13	1
11	(K16;01) HARRINGTON STA	NICHOLS STA	230.00	230.00	H-FRAME	1.06		1
12	(K15;01) JONES PLANT	LUBBOCK EAST	230.00	230.00	TOWER	2.55	3.72	1
13	(K14;02) JONES PLANT	LUBBOCK SOUTH	230.00	230.00	TOWER	0.08	5.35	1
14	(K11;01) BUSHLAND	DEAF SMITH INTERCHANGE	230.00	230.00	SINGLE POLE	33.52		1
15	(K10;01) LUBBOCK SOUTH	WOLFFORTH INTG	230.00	230.00	H-FRAME	14.78		1
16	(K08;01) JONES PLANT	LUBBOCK SOUTH	230.00	230.00	TOWER	5.39		1
17	(K07;01) JONES PLANT	TUCO	230.00	230.00	H-FRAME	20.70		1
18			230.00	230.00	TOWER	8.94		1
19	(K06;01) HUTCHINSON CO	NICHOLS STA	230.00	230.00	H-FRAME	1.15		1
20			230.00	230.00	K-FRAME	29.30		1
21	(K03;01) AMOCO SW. STA.	SUNDOWN SW. STA.	230.00	230.00	K-FRAME	5.31		1
22	(K02;01) SUNDOWN SW.	WOLFFORTH INTG	230.00	230.00	H-FRAME	7.54		1
23			230.00	230.00	K-FRAME	17.04		1
24	(K01;01) SWISHER CO INTG	TUCO	230.00	230.00	K-FRAME	39.61		1
25								
26	SUMMARY OF 115 KV		115.00	115.00	Overhead	3,115.20	246.01	
27			115.00	230.00	Overhead	4.05		
28			115.00	345.00	Overhead	0.19		
29	SUMMARY OF 69 KV		69.00	69.00	Overhead	1,143.82	282.61	
30			69.00	115.00	Overhead	44.22	4.19	
31			69.00	69.00	Underground	4.74		
32								
33								
34								
35								
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
6-795 ACSR		747,369	747,369					1
6-795 ACSR	871,770	3,919,636	4,791,406					2
6-795 ACSR								3
6-795 ACSR	1,157,018	8,019,180	9,176,197					4
6-795 ACSR	852,435	45,103,036	45,955,471					5
6-795 ACSS	2,240,588	18,713,830	20,954,418					6
6-795 ACSS	1,485,856	23,378,076	24,863,932					7
6-795 ACSS	11,736,379	39,394,557	51,130,936					8
6-795 ACSS								9
6-795 ACSS	2,433,233	36,328,281	38,761,514					10
6-795 ACSS	1,670,565	31,429,875	33,100,440					11
6-795 ACSR	241,431	3,100,618	3,342,049					12
6-795 ACSR	445,174	4,247,609	4,692,783					13
6-795 ACSR	1,368,108	17,667,895	19,036,003					14
6-1590 ACSR	54,107	6,964,051	7,018,158					15
6-1590 ACSR		150,186	150,186					16
6-1590 ACSR	1,859,566	40,145,041	42,004,606					17
6-1590 ACSR	34,262	1,743,136	1,777,398					18
6-795 ACSS	259,826	4,718,648	4,978,474					19
6-795 ACSS	32,988,616	171,136,448	204,125,064					20
6-795 ACSS								21
6-795 ACSS								22
6-795 ACSR	4,624,961	35,166,804	39,791,765					23
6-795 ACSR	49,567	21,958,432	22,007,999					24
6-795 ACSR	3,892,153	22,913,323	26,805,476					25
6-795 ACSR	2,428,536	25,893,053	28,321,589					26
3-795 ACSR		333,924	333,924					27
3-795 ACSR		388,191	388,191					28
3-795 ACSR								29
3-795 ACSR		490,248	490,248					30
3-795 ACSR		439,984	439,984					31
3-795 ACSR	334,131	10,516,153	10,850,284					32
3-795 ACSR								33
3-795 ACSR								34
3-795 ACSR	61,477	2,450,945	2,512,423					35
	155,943,819	1,757,317,909	1,913,261,725	662,806	1,000,520	2,187,682	3,851,008	36

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
3-795 ACSR								1
6-795 ACSR								2
6-795 ACSR		869,380	869,380					3
3-795 ACSR	2,799,489	8,909,555	11,709,044					4
3-795 ACSR	37,277	623,112	660,389					5
3-795 ACSR	66,461	778,059	844,521					6
6-795 ACSR	-1	658,485	658,484					7
6-795 ACSR								8
3-795 ACSR		1,354,632	1,354,632					9
3-795 ACSR		1,987,220	1,987,220					10
3-795 ACSR								11
3-795 ACSR	286,505	5,720,583	6,007,088					12
3-795 ACSR	891,615	10,915,732	11,807,347					13
3-795 ACSR	1,108,488	7,214,262	8,322,750					14
3-795 ACSR		1,138,599	1,138,599					15
3-795 ACSR		1,759,549	1,759,549					16
3-795 ACSR								17
3-795 ACSR	1,305,733	12,598,887	13,904,620					18
3-795 ACSR	886,966	12,641,398	13,528,364					19
3-795 ACSR								20
3-795 ACSR								21
3-795 ACSR	22,358	643,346	665,704					22
3-795 ACSR								23
3-795 ACSR	1,809,214	18,432,877	20,242,091					24
3-795 ACSR	2,565,040	28,946,409	31,511,449					25
3-795 ACSR								26
3-795 ACSR		1,104,510	1,104,510					27
3-795 ACSR		2,422,395	2,422,395					28
3-795 ACSR	880,706	8,383,885	9,264,591					29
3-795 ACSR	464,861	7,176,410	7,641,271					30
3-795 ACSR								31
3-795 ACSR	943,425	4,865,979	5,809,404					32
3-795 ACSR		1,524,820	1,524,820					33
3-795 ACSR								34
3-795 ACSR		580,914	580,914					35
	155,943,819	1,757,317,909	1,913,261,725	662,806	1,000,520	2,187,682	3,851,008	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
3-795 ACSR	192,413	3,712,463	3,904,875					1
3-795 ACSR								2
3-795 ACSR								3
3-795 ACSR		1,275,843	1,275,843					4
3-795 ACSR	373,453	6,280,883	6,654,336					5
3-795 ACSR		151,855	151,855					6
3-795 ACSR								7
3-795 ACSR								8
3-795 ACSR	110,146	3,452,773	3,562,919					9
3-795 ACSR								10
3-795 ACSR		117,523	117,523					11
3-795 ACSR	299,576	9,296,208	9,595,785					12
3-795 ACSR	35,679	7,767,507	7,803,186					13
3-795 ACSR	385,284	8,482,427	8,867,711					14
3-795 ACSR								15
6-795 ACSR	1,003,850	4,012,094	5,015,943					16
3-795 ACSR	753,723	14,507,555	15,261,278					17
3-795 ACSR								18
3-1011.3 ACCCULS	10,937	-81,919	-70,981					19
3-795 ACSR	74,484	2,503,898	2,578,382					20
3-795 ACSR	691,754	7,711,956	8,403,710					21
3-795 ACSR	80,573	5,067,988	5,148,562					22
3-795 ACSR								23
3-795 ACSR								24
3-795 ACSR	262,396	5,650,302	5,912,698					25
3-795 ACSR								26
3-795 ACSR	194,338	4,499,286	4,693,624					27
3-795 ACSR								28
3-795 ACSR	104,491	3,191,790	3,296,281					29
3-795 ACSR	71,645	502,725	574,370					30
3-795 ACSR	344,824	4,602,204	4,947,028					31
3-795 ACSR	1,375,140	5,465,581	6,840,721					32
3-795 ACSR								33
3-795 ACSR								34
3-795 ACCR		-121,133	-121,133					35
	155,943,819	1,757,317,909	1,913,261,725	662,806	1,000,520	2,187,682	3,851,008	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
3-795 ACSR	1,418,653	16,537,913	17,956,565					1
3-795 ACSR								2
3-795 ACSR	10,840	7,241,011	7,251,851					3
3-795 ACSR		5,837,633	5,837,633					4
3-795 ACSR								5
3-795 ACSR	241	764,320	764,561					6
3-795 ACSR								7
3-795 ACSR	10,898	533,989	544,887					8
3-795 ACSR	177,164	8,880,921	9,058,085					9
3-795 ACSS		41,452	41,452					10
3-795 ACCC		121,547	121,547					11
3-795 ACSR	40,416	722,252	762,667					12
3-795 ACSR		281,393	281,393					13
3-795 ACSR		1,256,372	1,256,372					14
3-795 ACSR		458,587	458,587					15
3-795 ACSR	98,926	1,230,909	1,329,835					16
3-795 ACSR	205,589	2,582,135	2,787,724					17
3-795 ACSR								18
3-795 ACSR	50,912	3,634,220	3,685,131					19
3-795 ACSR								20
3-795 ACSR	143,180	4,156,829	4,300,009					21
3-795 ACSR	177,182	4,789,881	4,967,063					22
3-795 ACSR								23
3-795 ACSR								24
								25
	58,529,734	715,273,994	773,803,728					26
								27
								28
	3,557,482	166,213,215	169,770,696					29
								30
								31
								32
								33
								34
				662,806	1,000,520	2,187,682	3,851,008	35
	155,943,819	1,757,317,909	1,913,261,725	662,806	1,000,520	2,187,682	3,851,008	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	(J18-NM;01) HOBBS	YOAKUM CO INTG	36.44	H-FRAME	6.00	1	1
2	(U01;01) MUSTANG INTG	SHELL CO2	8.99	SINGLE POLE	10.00	1	1
3	(U08;01) LIVINGSTON	POTASH JUNCTION	5.58	SINGLE POLE	15.00	1	1
4	(U18;01) LOVING SOUTH	NORTH LOVING	3.55	SINGLE POLE	9.00	1	1
5	(W26:01) CUNNINGHAM	OIL CENTER	6.42	SINGLE POLE	9.00	1	1
6	(W87;01) CHINA DRAW	CHEVRON SOUTH EDDY	3.94	SINGLE POLE	16.00	1	1
7	(W92;01) ATOKA	EAGLE CREEK	2.76	SINGLE POLE	9.00	1	1
8	(Y96;01) BRISCOE	LOCKNEY RURAL	6.12	SINGLE POLE	36.00	1	1
9							
10							
11							
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44	TOTAL		73.80		110.00	8	8

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
6-795	ACSS	26/7	345	3,164	29,895,607	6,432,673		36,331,444	1
3-477	ACSS	26/7	115		5,798,691	1,659,590		7,458,281	2
3-477	ACSS	26/7	115		5,763,174	2,447,150		8,210,324	3
3-477	ACSS	26/7	115		2,205,337	587,150		2,792,487	4
3-477	ACSS	26/7	115	213,294	2,294,965	874,300		3,382,559	5
3-477	ACSS	26/7	115		1,810,544	940,118		2,750,662	6
3-477	ACSS	26/7	115		1,706,187	327,689		2,033,876	7
3-1/0	ACSR	6/1	69		334,855	87,451		422,306	8
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				216,458	49,809,360	13,356,121		63,381,939	44

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	34TH STREET PUMP-T1W,T1E,T1	UNATTENDED DISTRIB	13.20	2.40	
2	34TH STREET-TR01	UNATTENDED DISTRIB	115.00	13.20	
3	3RD & WESTERN-T1	UNATTENDED DISTRIB	13.20	4.16	
4	8TH & BONHAM-T1	UNATTENDED DISTRIB	13.20	4.16	
5	8TH & BONHAM-T2	UNATTENDED DISTRIB	13.20	4.16	
6	ADAIR-T1	UNATTENDED DISTRIB	69.00	12.50	
7	ADOBE CREEK-T1	UNATTENDED DISTRIB	69.00	12.50	
8	ADOBE CREEK-T2	UNATTENDED DISTRIB	69.00	4.16	
9	AIKEN RURAL-T1	UNATTENDED DISTRIB	69.00	12.50	
10	ALLMON-T1	UNATTENDED DISTRIB	69.00	12.50	
11	ALLRED-T1	UNATTENDED DISTRIB	69.00	12.50	
12	AMARILLO SOUTH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
13	AMFRAC-T1	UNATTENDED DISTRIB	115.00	2.40	
14	AMHERST-T1	UNATTENDED DISTRIB	69.00	2.40	
15	AMOCO YELLOWHOUSE-T1	UNATTENDED DISTRIB	69.00	12.50	
16	ANDREWS COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
17	ANDREWS COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
18	ANTON WEST-T1	UNATTENDED DISTRIB	69.00	12.50	12.50
19	ARROWHEAD-T1	UNATTENDED DISTRIB	115.00	13.20	
20	ARROWHEAD-T1	UNATTENDED DISTRIB	115.00	13.20	
21	ARTESIA 13TH STREET-T1	UNATTENDED DISTRIB	69.00	4.16	
22	ARTESIA CITY OR TOWN-T1	UNATTENDED DISTRIB	69.00	4.16	
23	ARTESIA COUNTRY CLUB-T1	UNATTENDED TRANSM	12.50	69.00	
24	ARTESIA SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
25	ARTESIA-T1	UNATTENDED TRANSM	115.00	69.00	
26	ARTESIA-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	ATLANTIC-T1W,T1E,T1	UNATTENDED DISTRIB	23.00	2.40	
28	ATOKA-T1	UNATTENDED TRANSM	115.00	69.00	13.20
29	BAILEY COUNTY PUMP-T1	UNATTENDED DISTRIB	69.00	12.50	
30	BAILEY COUNTY-T1	UNATTENDED DISTRIB	69.00	12.50	
31	BAILEY COUNTY-T1E	UNATTENDED DISTRIB	69.00	12.50	
32	BAILEY COUNTY-T1W	UNATTENDED DISTRIB	69.00	12.50	
33	BAILEY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	
34	BAILEY COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	13.20
35	BAINER-T1W,T1E,T1	UNATTENDED DISTRIB	69.00	2.40	
36	BARWISE-T1	UNATTENDED DISTRIB	69.00	12.50	
37	BATTLE AXE-T1	UNATTENDED DISTRIB	115.00	13.20	
38	BATTLE AXE-T2	UNATTENDED DISTRIB	115.00	13.20	
39	BENNETT-T1	UNATTENDED DISTRIB	115.00	13.20	
40	BLACKHAWK-T1	UNATTENDED TRANSM	115.00	69.00	13.20

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BLACKHAWK-T2	UNATTENDED TRANSM	115.00	69.00	13.20
2	BLODGETT-T1	UNATTENDED DISTRIB	12.50	2.40	
3	BOARDMAN-T1	UNATTENDED DISTRIB	69.00	12.50	
4	BOLTON PUMP-T1	UNATTENDED DISTRIB	12.50	2.40	
5	BONBRIGHT-T1	UNATTENDED DISTRIB	12.50	2.40	
6	BONBRIGHT-T2	UNATTENDED DISTRIB	12.50	2.40	
7	BOOKER-T1	UNATTENDED DISTRIB	69.00	34.50	
8	BOOKER-T2	UNATTENDED DISTRIB	69.00	4.16	
9	BORGER ISOM-T1	UNATTENDED DISTRIB	13.20	4.16	
10	BORGER NORTH-T1	UNATTENDED DISTRIB	12.50	4.16	
11	BORGER WEST-T1	UNATTENDED DISTRIB	115.00	13.20	
12	BOWERS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
13	BOWERS-T2	UNATTENDED TRANSM	115.00	69.00	13.20
14	BOWERS-T3	UNATTENDED TRANSM	115.00	69.00	13.20
15	BRASHER-T1	UNATTENDED DISTRIB	115.00	13.20	
16	BRISCOE COUNTY-T1	UNATTENDED DISTRIB	69.00	23.00	
17	BROWNFIELD SWITCHING-T1	UNATTENDED DISTRIB	69.00	23.00	
18	BUCKEYE-T1	UNATTENDED DISTRIB	115.00	12.50	
19	BUFFALO-T1	UNATTENDED DISTRIB	69.00	12.50	
20	BURNETT-T1	UNATTENDED DISTRIB	69.00	13.20	
21	BUSHLAND-T1	UNATTENDED TRANSM	230.00	115.00	13.20
22	BUSH-T1	UNATTENDED DISTRIB	115.00	13.80	
23	BYRD-T1	UNATTENDED DISTRIB	115.00	4.16	
24	CAMEX TRANSPETCO-T1	UNATTENDED DISTRIB	69.00	4.16	
25	CAMEX TRANSPETCO-T2	UNATTENDED DISTRIB	69.00	4.16	
26	CAMEX TRANSPETCO-T3	UNATTENDED DISTRIB	69.00	13.20	
27	CAMPBELL ST-T1	UNATTENDED DISTRIB	115.00	12.50	
28	CANADIAN-T1	UNATTENDED DISTRIB	69.00	4.16	
29	CANNON AFB-T1	UNATTENDED DISTRIB	115.00	13.20	
30	CANYON EAST-T1	UNATTENDED DISTRIB	115.00	13.20	
31	CANYON WEST-TR01	UNATTENDED DISTRIB	115.00	13.20	
32	CAPITAN-T1	UNATTENDED DISTRIB	115.00	13.20	
33	CARLISLE-T1	UNATTENDED TRANSM	230.00	115.00	13.20
34	CARLISLE-T2	UNATTENDED TRANSM	115.00	69.00	13.20
35	CARLISLE-T3	UNATTENDED DISTRIB	115.00	23.00	
36	CARLSBAD CAVERN-T1W,T1E,T1	UNATTENDED DISTRIB	12.50	2.40	
37	CARLSBAD WATERFIELD-T1	UNATTENDED DISTRIB	69.00	23.00	
38	CARLSBAD-T1	UNATTENDED TRANSM	115.00	69.00	13.20
39	CARLSBAD-T2	UNATTENDED TRANSM	115.00	69.00	
40	CARLSBAD-T3	UNATTENDED DISTRIB	69.00	13.20	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CARSON CO-T1	UNATTENDED DISTRIB	115.00	13.80	
2	CASTRO COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
3	CASTRO COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	
4	CEDAR LAKE EAST-T1W,T1E,T1	UNATTENDED DISTRIB	69.00	12.50	
5	CENTRE STREET-T1	UNATTENDED DISTRIB	69.00	13.20	
6	CHANNING-T1	UNATTENDED DISTRIB	230.00	34.50	19.90
7	CHANNING-T2	UNATTENDED DISTRIB	230.00	34.50	19.90
8	CHAVES COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
9	CHAVES COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
10	CHAVES COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	
11	CHERRY STREET-T1	UNATTENDED DISTRIB	115.00	13.20	
12	CHINADRAW-SVC	UNATTENDED TRANSM	115.00	69.00	
13	CHINADRAW-TR01	UNATTENDED DISTRIB	115.00	13.20	
14	CHINADRAW-TR02	UNATTENDED DISTRIB	115.00	13.20	
15	CLIFFSIDE-T1	UNATTENDED DISTRIB	69.00	4.16	
16	CLOSE CITY-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
17	CLOVIS CITY-T1	UNATTENDED DISTRIB	23.00	4.16	
18	CLOVIS EAST-T1	UNATTENDED DISTRIB	115.00	13.20	
19	CLOVIS NORTH-T1	UNATTENDED DISTRIB	115.00	12.50	
20	CLOVIS PARK EAST-T1	UNATTENDED DISTRIB	23.00	4.16	
21	CLOVIS WEST-T1	UNATTENDED DISTRIB	115.00	13.20	
22	CLOVIS WEST-T2	UNATTENDED DISTRIB	69.00	23.00	
23	COBLE-T1	UNATTENDED DISTRIB	69.00	12.50	
24	COBURN CREEK-T1	UNATTENDED DISTRIB	115.00	13.20	
25	COCHRAN COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	COCHRAN COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	CONE-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
28	CONWAY-T1	UNATTENDED DISTRIB	115.00	13.20	
29	COOPER RANCH-T1	UNATTENDED DISTRIB	115.00	13.20	
30	CORTEZ-T1	UNATTENDED DISTRIB	115.00	4.16	2.40
31	COTTONWOOD-T1	UNATTENDED DISTRIB	69.00	12.50	
32	COULTER-T1	UNATTENDED DISTRIB	115.00	13.80	
33	COULTER-T2	UNATTENDED TRANSM	115.00	69.00	
34	COUNTY LINE-T1	UNATTENDED DISTRIB	69.00	12.50	2.40
35	COX-T1	UNATTENDED TRANSM	115.00	69.00	13.20
36	CRMWA #1-T1	UNATTENDED DISTRIB	115.00	4.16	
37	CRMWA #22-T1	UNATTENDED DISTRIB	69.00	4.16	
38	CRMWA #23-T1	UNATTENDED DISTRIB	69.00	13.80	
39	CRMWA #2-T1	UNATTENDED DISTRIB	115.00	4.16	
40	CRMWA #3-T1	UNATTENDED DISTRIB	115.00	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CRMWA #4-T1	UNATTENDED DISTRIB	115.00	4.16	
2	CROSBY COUNTY INTERCHANGE-T1	UNATTENDED TRANSM	115.00	69.00	13.20
3	CROSBY COUNTY INTERCHANGE-T2	UNATTENDED TRANSM	115.00	69.00	13.20
4	CROSBYTON-T1	UNATTENDED DISTRIB	23.00	4.16	
5	CROUSE-HINDS-T1	UNATTENDED DISTRIB	115.00	13.80	
6	CUNNINGHAM-T1	UNATTENDED TRANSM	230.00	115.00	13.20
7	CURRY COUNTY-T1	UNATTENDED DISTRIB	69.00	2.40	
8	CURRY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
9	CURRY COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	13.20
10	DALHART-T1	UNATTENDED DISTRIB	69.00	2.40	
11	DALHART-T2	UNATTENDED TRANSM	115.00	69.00	13.20
12	DALHART-T3	UNATTENDED DISTRIB	69.00	12.50	
13	DALHART-T4	UNATTENDED DISTRIB	69.00	34.50	
14	DALLAM COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
15	DAMRON-T1	UNATTENDED DISTRIB	69.00	13.20	
16	DAMRON-T2	UNATTENDED DISTRIB	13.20	2.40	
17	DARROUZETT-T1W,T1E,T1	UNATTENDED DISTRIB	34.50	4.16	
18	DAWN-T1	UNATTENDED DISTRIB	115.00	13.20	
19	DEAF SMITH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	DEAF SMITH-T2	UNATTENDED TRANSM	230.00	115.00	13.20
21	DEAF SMITH-T3	UNATTENDED DISTRIB	115.00	13.80	
22	DENVER CITY EAST-T1	UNATTENDED DISTRIB	69.00	7.20	
23	DENVER CITY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
24	DENVER CITY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
25	DEXTER INTERCHANGE-T1	UNATTENDED DISTRIB	69.00	34.50	
26	DEXTER-T1	UNATTENDED DISTRIB	69.00	4.16	
27	DIAMONDBACK-T1	UNATTENDED TRANSM	115.00	69.00	13.20
28	DIEKEMPER-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	4.16	
29	DIMMITT EAST-T1	UNATTENDED DISTRIB	69.00	13.20	
30	DIMMITT SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
31	DOLLARHIDE-T1	UNATTENDED DISTRIB	115.00	12.50	
32	DOSS-T1	UNATTENDED DISTRIB	69.00	23.00	
33	DOSS-T2	UNATTENDED DISTRIB	69.00	12.50	
34	DOSS-T3	UNATTENDED TRANSM	115.00	69.00	
35	DRINKARD-T1	UNATTENDED DISTRIB	115.00	12.50	
36	DUMAS 19TH STREET-T1	UNATTENDED DISTRIB	115.00	34.50	
37	DUMAS 19TH STREET-T2	UNATTENDED DISTRIB	115.00	12.50	
38	DUMAS EAST-T1	UNATTENDED DISTRIB	34.50	12.50	
39	DUMAS HELIUM-T1	UNATTENDED DISTRIB	34.50	12.50	
40	DUMAS NORTH-T1	UNATTENDED DISTRIB	34.50	2.40	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DUMAS SOUTH-T1	UNATTENDED DISTRIB	34.50	2.40	
2	EAGLE CREEK-T1	UNATTENDED TRANSM	115.00	69.00	13.20
3	EAST PLANT-T1	UNATTENDED DISTRIB	115.00	13.20	
4	EAST PLANT-T2	UNATTENDED TRANSM	230.00	115.00	13.20
5	EAST PLANT-T3	UNATTENDED TRANSM	115.00	69.00	13.20
6	EAST PLANT-T4	UNATTENDED TRANSM	115.00	69.00	
7	EAST PLANT-T5W,T5E,T5	UNATTENDED DISTRIB	13.20	2.40	
8	EAST SANGER-T1	UNATTENDED DISTRIB	115.00	12.50	
9	EDDY COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
10	EDDY COUNTY-T2	UNATTENDED DISTRIB	230.00	8.50	
11	EDDY COUNTY-T3	UNATTENDED TRANSM	345.00	230.00	
12	EDDY COUNTY-T4	UNATTENDED TRANSM	230.00	115.00	13.20
13	EFDC GRAIN POWER PORTALES NM-T1	UNATTENDED DISTRIB	69.00	4.16	
14	ELBERT-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
15	ELLWOOD-T1	UNATTENDED DISTRIB	69.00	12.50	
16	ESTACADO-T1	UNATTENDED DISTRIB	115.00	13.20	
17	ESTACADO-T2	UNATTENDED DISTRIB	115.00	13.20	
18	ETTER RURAL-T1	UNATTENDED DISTRIB	115.00	34.50	
19	ETTER RURAL-T2	UNATTENDED DISTRIB	115.00	34.50	
20	EUNICE-T1	UNATTENDED DISTRIB	115.00	13.20	
21	EXELL-T1	UNATTENDED DISTRIB	115.00	12.50	
22	FAIN-T1	UNATTENDED DISTRIB	115.00	12.50	
23	FARMERS-T1	UNATTENDED DISTRIB	115.00	13.20	
24	FARWELL-T1	UNATTENDED DISTRIB	69.00	2.40	
25	FIESTA-T1	UNATTENDED DISTRIB	115.00	12.50	
26	FLANAGAN-T1	UNATTENDED DISTRIB	69.00	12.50	
27	FLOYD COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
28	FLOYD COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
29	FLOYDADA CITY-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
30	FLOYDADA CITY-T2S,T2N,T2	UNATTENDED DISTRIB	23.00	2.40	
31	FLOYDADA CITY-T3	UNATTENDED DISTRIB	24.00	13.80	
32	FLOYDADA SOUTH-T1	UNATTENDED DISTRIB	69.00	23.00	
33	FOLLETT-T1S,T1,T1N	UNATTENDED DISTRIB	34.50	4.16	
34	FRIONA CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
35	FRIONA RURAL-T1	UNATTENDED DISTRIB	115.00	23.00	
36	FRITCH-T1	UNATTENDED DISTRIB	115.00	13.20	
37	GAINES COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
38	GAINES COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
39	GARZA-T1	UNATTENDED DISTRIB	69.00	23.00	
40	GARZA-T2	UNATTENDED DISTRIB	69.00	23.00	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GARZA-T3	UNATTENDED DISTRIB	69.00	2.40	
2	GOODPASTURE-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	12.50	
3	GRAHAM-T1	UNATTENDED TRANSM	115.00	69.00	13.20
4	GRAHAM-T2	UNATTENDED TRANSM	115.00	69.00	13.20
5	GRAPEVINE-T1	UNATTENDED TRANSM	230.00	115.00	13.20
6	GRASSLAND-T1	UNATTENDED TRANSM	230.00	115.00	13.20
7	GRAY COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
8	GREEN HEIGHTS-T1	UNATTENDED DISTRIB	12.50	2.40	
9	GRUVER-T1	UNATTENDED DISTRIB	34.50	12.50	
10	HAGERMAN TOWN-T1	UNATTENDED DISTRIB	23.00	4.16	
11	HAGERMAN WEST RURAL-T1	UNATTENDED DISTRIB	34.50	2.40	
12	HALE CENTER-T1	UNATTENDED DISTRIB	69.00	13.20	
13	HALE COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
14	HALE COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
15	HAPPY CITY-T1	UNATTENDED DISTRIB	69.00	12.50	
16	HAPPY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
17	HAPPY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
18	HARTLEY-T1S,T1N,T1	UNATTENDED DISTRIB	34.50	2.40	
19	HART-T1	UNATTENDED DISTRIB	115.00	13.20	
20	HASTINGS-T1	UNATTENDED DISTRIB	115.00	13.20	
21	HENDRICKS-T1	UNATTENDED DISTRIB	69.00	23.00	
22	HEREFORD CITY-T1	UNATTENDED DISTRIB	69.00	13.80	
23	HEREFORD NORTH EAST-T1	UNATTENDED TRANSM	115.00	69.00	13.20
24	HEREFORD NORTH EAST-T2	UNATTENDED TRANSM	115.00	69.00	13.20
25	HEREFORD SOUTH-T1	UNATTENDED TRANSM	115.00	69.00	
26	HEREFORD-T1	UNATTENDED TRANSM	115.00	69.00	13.20
27	HERRING-T1	UNATTENDED DISTRIB	115.00	34.50	
28	HIGG EAST-T1	UNATTENDED DISTRIB	115.00	13.20	
29	HIGGINS-T1W,T1E,T1	UNATTENDED DISTRIB	34.50	4.16	
30	HIGHLAND PARK-T1	UNATTENDED DISTRIB	115.00	13.80	
31	HITCHLAND-T1	UNATTENDED TRANSM	345.00	230.00	
32	HITCHLAND-T2	UNATTENDED TRANSM	230.00	115.00	13.20
33	HITCHLAND-T3	UNATTENDED TRANSM	345.00	230.00	
34	HOBBS GENERATING-T1	UNATTENDED TRANSM	230.00	115.00	13.20
35	HOBBS GENERATING-T2	UNATTENDED TRANSM	230.00	115.00	13.20
36	HOBBS NE-T1	UNATTENDED DISTRIB	115.00	12.50	
37	HOBBS NORTH-T1	UNATTENDED DISTRIB	115.00	12.50	
38	HOBBS NORTH-T2	UNATTENDED DISTRIB	115.00	12.50	
39	HOBBS SOUTH-T1	UNATTENDED DISTRIB	115.00	12.50	
40	HOBBS SOUTH-T2	UNATTENDED DISTRIB	115.00	13.20	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HOBGOOD-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	2.40	
2	HOCKLEY COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
3	HOCKLEY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
4	HOPI-T1	UNATTENDED DISTRIB	115.00	13.20	
5	HOWARD-T1	UNATTENDED DISTRIB	115.00	13.20	
6	HOWARD-T2	UNATTENDED TRANSM	115.00	69.00	13.20
7	HOWARD-T3	UNATTENDED TRANSM	115.00	69.00	13.20
8	HUTCHINSON COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	
9	HUTCHINSON COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
10	HUTCHINSON COUNTY-T3	UNATTENDED TRANSM	230.00	115.00	13.20
11	HVDC TIE-T2	UNATTENDED TRANSM	230.00	115.00	
12	HVDC TIE-T3	UNATTENDED DISTRIB	345.00	34.50	
13	IDALOU-T1	UNATTENDED DISTRIB	23.00	4.16	
14	IMC #4-T1	UNATTENDED DISTRIB	69.00	13.20	
15	INDUSTRIAL-T1	UNATTENDED DISTRIB	69.00	13.20	
16	INK BASIN-TR1	UNATTENDED TRANSM	230.00	115.00	13.20
17	IRICK-T1	UNATTENDED DISTRIB	69.00	13.20	
18	JAL-T1	UNATTENDED DISTRIB	115.00	13.80	
19	JAYBEE-T1	UNATTENDED DISTRIB	69.00	12.50	
20	KERRICK PUMP-T1S,T1N,T1	UNATTENDED DISTRIB	34.50	2.40	
21	KILGORE-T1	UNATTENDED DISTRIB	115.00	13.20	
22	KINGSMILL-T1	UNATTENDED DISTRIB	115.00	12.50	15.00
23	KINGSMILL-T2	UNATTENDED TRANSM	115.00	69.00	13.20
24	KINGSMILL-T3	UNATTENDED DISTRIB	69.00	13.80	
25	KINNEY-T1W,T1E,T1	UNATTENDED DISTRIB	69.00	2.40	
26	KISER-T1	UNATTENDED TRANSM	115.00	69.00	13.20
27	KITE-T1	UNATTENDED DISTRIB	69.00	13.20	
28	KRESS RURAL-T1	UNATTENDED DISTRIB	115.00	13.20	
29	KRESS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
30	LAKE MEREDITH-T1	UNATTENDED DISTRIB	115.00	4.16	
31	LAMB COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
32	LAMB COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
33	LAMB COUNTY-T3	UNATTENDED TRANSM	115.00	69.00	13.20
34	LAMTON-T1	UNATTENDED TRANSM	115.00	69.00	13.20
35	LARIAT-T1	UNATTENDED DISTRIB	69.00	12.50	
36	LAWRENCE PARK-T1	UNATTENDED DISTRIB	69.00	13.80	
37	LAWRENCE PARK-T2	UNATTENDED DISTRIB	69.00	13.80	
38	LEA NATIONAL-T1	UNATTENDED DISTRIB	115.00	12.50	
39	LEA ROAD-T1	UNATTENDED DISTRIB	115.00	12.50	
40	LEGACY-T1	UNATTENDED TRANSM	115.00	69.00	13.20

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LEHMAN-T1	UNATTENDED DISTRIB	115.00	12.50	
2	LEVELLAND CITY-T1	UNATTENDED DISTRIB	69.00	12.50	
3	LEVELLAND CITY-T2W,T2E,T2	UNATTENDED DISTRIB	12.50	2.40	
4	LEVELLAND CITY-T3W,T3E,T3	UNATTENDED DISTRIB	69.00	2.40	
5	LEVELLAND EAST-T1	UNATTENDED DISTRIB	69.00	12.50	
6	LIPSCOMB CO-T1	UNATTENDED DISTRIB	115.00	34.50	
7	LIPSCOMB CO-T2	UNATTENDED DISTRIB	115.00	13.20	
8	LITTLEFIELD CITY-T1	UNATTENDED DISTRIB	69.00	4.16	
9	LITTLEFIELD SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
10	LITTLEFIELD WEST-T1	UNATTENDED DISTRIB	69.00	12.50	
11	LITTLEFIELD WEST-T1W,T1E	UNATTENDED DISTRIB	69.00	7.20	
12	LIVINGSTON RIDGE-T1	UNATTENDED DISTRIB	69.00	12.50	
13	LOCKNEY CITY-T1	UNATTENDED DISTRIB	23.00	12.50	
14	LOCKNEY RURAL-T1	UNATTENDED DISTRIB	69.00	23.00	
15	LOCKNEY RURAL-T2W,T2E,T2	UNATTENDED DISTRIB	69.00	12.50	
16	LOCKNEY WEST-T1	UNATTENDED DISTRIB	23.00	7.20	
17	LORENZO-T1	UNATTENDED DISTRIB	23.00	4.16	
18	LOVING SOUTH-T1	UNATTENDED DISTRIB	69.00	13.20	
19	LUBBOCK EAST-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	LUBBOCK EAST-T2	UNATTENDED TRANSM	115.00	69.00	13.20
21	LUBBOCK EAST-T3	UNATTENDED TRANSM	115.00	69.00	13.20
22	LUBBOCK SOUTH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
23	LUBBOCK SOUTH-T2	UNATTENDED TRANSM	115.00	69.00	13.20
24	LUBBOCK SOUTH-T3	UNATTENDED TRANSM	230.00	115.00	13.20
25	LYNN COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	LYNN COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	LYNN COUNTY-T3	UNATTENDED DISTRIB	115.00	23.00	
28	LYONS-T1	UNATTENDED DISTRIB	69.00	13.80	
29	MAGNOLIA PUMP STATION-T1	UNATTENDED DISTRIB	24.00	2.40	
30	MALJAMAR #1-T1	UNATTENDED DISTRIB	115.00	12.50	
31	MALJAMAR 2-T1	UNATTENDED DISTRIB	115.00	12.50	
32	MALLET-T1	UNATTENDED DISTRIB	69.00	12.50	
33	MANHATTAN-T1	UNATTENDED DISTRIB	115.00	13.20	
34	MARKET STREET-T1	UNATTENDED DISTRIB	69.00	12.50	
35	MCCLELLAN PUMP-T1	UNATTENDED DISTRIB	115.00	13.20	
36	MCCULLOUGH-T1	UNATTENDED DISTRIB	69.00	13.20	
37	MCLEAN RURAL-T1	UNATTENDED DISTRIB	115.00	13.20	
38	MID AMERICA #3-T1	UNATTENDED DISTRIB	69.00	2.40	
39	MID-AMERICA #2-T1	UNATTENDED DISTRIB	69.00	2.40	
40	MIDDLETON-T1	UNATTENDED DISTRIB	69.00	12.50	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MILLEN-T1	UNATTENDED DISTRIB	115.00	7.20	
2	MITCHELL STREET-T1	UNATTENDED DISTRIB	23.00	4.16	
3	MONROE-T1	UNATTENDED DISTRIB	69.00	23.00	
4	MONUMENT-T1	UNATTENDED DISTRIB	115.00	12.50	
5	MOORE COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
6	MOORE COUNTY-T2	UNATTENDED DISTRIB	115.00	13.20	
7	MORTON-T1	UNATTENDED DISTRIB	69.00	4.16	
8	MOSS-T1	UNATTENDED DISTRIB	69.00	23.00	
9	MULESHOE VALLEY-T1	UNATTENDED DISTRIB	115.00	13.20	
10	MULESHOE WEST-T1	UNATTENDED DISTRIB	69.00	12.50	
11	MURPHY-T1	UNATTENDED DISTRIB	115.00	23.00	
12	MUSTANG-T1	UNATTENDED TRANSM	230.00	115.00	13.20
13	NAVAJO #1-T1	UNATTENDED DISTRIB	69.00	2.40	
14	NAVAJO #2-T1	UNATTENDED DISTRIB	115.00	4.16	
15	NAVAJO #3-T1	UNATTENDED DISTRIB	115.00	4.16	
16	NAVAJO #4-T1	UNATTENDED DISTRIB	69.00	2.40	
17	NAVAJO #5-T1	UNATTENDED DISTRIB	115.00	4.16	
18	NAVAJO-MALAGA-T1	UNATTENDED DISTRIB	69.00	4.16	
19	NEWHART-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	NICHOLS-T7	UNATTENDED TRANSM	230.00	115.00	13.20
21	NICHOLS-T8	UNATTENDED TRANSM	230.00	115.00	13.20
22	NM POTASH #2-T1	UNATTENDED DISTRIB	69.00	13.80	
23	NORRIS ST-T1	UNATTENDED DISTRIB	115.00	13.20	
24	NORTH CANAL-T1	UNATTENDED DISTRIB	115.00	12.50	
25	NORTH LOVING-T1	UNATTENDED DISTRIB	115.00	13.20	
26	NORTHWEST-T1	UNATTENDED TRANSM	115.00	69.00	
27	OASIS-T1	UNATTENDED TRANSM	230.00	115.00	13.20
28	OCHILTREE-T1	UNATTENDED TRANSM	230.00	115.00	
29	OCHOA-T1	UNATTENDED DISTRIB	115.00	13.20	
30	OCOTILLO-T1	UNATTENDED DISTRIB	115.00	13.20	
31	OLTON-T1	UNATTENDED DISTRIB	69.00	7.20	
32	ONG-T1	UNATTENDED DISTRIB	13.20	4.16	
33	OSAGE PUMP-T1W,T1E,T1	UNATTENDED DISTRIB	13.20	2.40	
34	OSAGE PUMP-T2S,T2N,T2	UNATTENDED DISTRIB	13.20	2.40	
35	OSAGE-T1	UNATTENDED DISTRIB	115.00	13.20	
36	OWENS-CORNING-T1	UNATTENDED DISTRIB	115.00	13.80	
37	OWENS-CORNING-T2	UNATTENDED DISTRIB	115.00	13.80	
38	PACIFIC-T1	UNATTENDED DISTRIB	115.00	12.50	
39	PALO DURO-T1	UNATTENDED DISTRIB	115.00	13.20	
40	PARMER COUNTY-T1	UNATTENDED DISTRIB	115.00	23.00	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	PCA-T1	UNATTENDED TRANSM	115.00	69.00	13.20
2	PCA-T2	UNATTENDED DISTRIB	69.00	13.20	
3	PEARL-T1	UNATTENDED DISTRIB	115.00	12.50	
4	PECOS-T1	UNATTENDED TRANSM	230.00	115.00	
5	PECOS-T2	UNATTENDED DISTRIB	115.00	13.20	
6	PERIMETER-T1	UNATTENDED DISTRIB	115.00	13.20	
7	PERRYTON-T1	UNATTENDED DISTRIB	115.00	12.50	
8	PERRYTON-T4S,T4N,T4	UNATTENDED TRANSM	115.00	69.00	
9	PHILLIPS PUMP #1-T1	UNATTENDED DISTRIB	69.00	2.40	
10	PHILLIPS PUMP #2-T1	UNATTENDED DISTRIB	69.00	2.40	
11	PIERCE STREET-T1	UNATTENDED DISTRIB	115.00	13.20	
12	PLAINVIEW CITY-T1W,T1E,T1,T1	UNATTENDED DISTRIB	69.00	2.40	
13	PLAINVIEW CITY-T2W,T2E,T2	UNATTENDED DISTRIB	69.00	2.40	
14	PLAINVIEW EAST-T1	UNATTENDED DISTRIB	69.00	12.50	
15	PLAINVIEW NORTH-T1	UNATTENDED DISTRIB	115.00	13.20	
16	PLAINVIEW SOUTH-T1	UNATTENDED DISTRIB	69.00	12.50	
17	PLAINVIEW WESTRIDGE-T1	UNATTENDED DISTRIB	69.00	7.20	
18	PLAINVIEW WEST-T1	UNATTENDED DISTRIB	69.00	12.50	
19	PLANT X-T1	UNATTENDED TRANSM	230.00	115.00	13.20
20	PLANT X-T19	UNATTENDED DISTRIB	115.00	12.50	
21	PLEASANT HILL-T1	UNATTENDED TRANSM	230.00	115.00	13.20
22	PORTALES #1-T1	UNATTENDED DISTRIB	69.00	4.16	
23	PORTALES #2-T1	UNATTENDED DISTRIB	69.00	12.50	7.20
24	PORTALES #2-T2	UNATTENDED DISTRIB	69.00	4.16	
25	PORTALES INTERCHANGE-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	PORTALES INTERCHANGE-T2	UNATTENDED TRANSM	115.00	69.00	13.20
27	PORTALES WATERFIELD-T1	UNATTENDED DISTRIB	115.00	13.20	
28	POTASH JUNCTION-T1	UNATTENDED TRANSM	230.00	115.00	13.20
29	POTASH JUNCTION-T2	UNATTENDED TRANSM	115.00	69.00	13.20
30	POTASH JUNCTION-T3	UNATTENDED TRANSM	115.00	69.00	13.20
31	POTTER COUNTY-T1	UNATTENDED TRANSM	345.00	230.00	13.20
32	POTTER COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	
33	POTTER COUNTY-T3	UNATTENDED TRANSM	230.00	115.00	13.20
34	PRENTICE-T1	UNATTENDED DISTRIB	115.00	12.50	
35	PRICE-T1	UNATTENDED DISTRIB	69.00	12.50	
36	PRINGLE OIL FIELD-T1	UNATTENDED DISTRIB	34.50	12.50	
37	PRINGLE-T1	UNATTENDED TRANSM	230.00	115.00	13.20
38	PRINGLE-T2	UNATTENDED DISTRIB	115.00	34.50	
39	PUCKETT WEST-T1	UNATTENDED DISTRIB	115.00	13.20	
40	PULLMAN-T1	UNATTENDED DISTRIB	115.00	13.20	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	RALLS-T1W,T1E,T1	UNATTENDED DISTRIB	23.00	2.40	
2	RANDALL COUNTY-T1	UNATTENDED DISTRIB	230.00	13.20	
3	RANDALL COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20
4	RILEY-T1	UNATTENDED DISTRIB	69.00	7.20	
5	RIVERVIEW-T2	UNATTENDED DISTRIB	115.00	13.20	
6	RIVERVIEW-T3	UNATTENDED TRANSM	115.00	69.00	
7	ROADRUNNER-T1	UNATTENDED TRANSM	230.00	115.00	13.20
8	ROADRUNNER-T2 SVC	UNATTENDED TRANSM	345.00	115.00	13.20
9	ROADRUNNER-TR3	UNATTENDED DISTRIB	115.00	22.86	
10	ROBERTS COUNTY-T1 NEW	UNATTENDED DISTRIB	69.00	7.20	
11	ROLLING HILLS-T1	UNATTENDED TRANSM	230.00	115.00	13.20
12	ROOSEVELT COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
13	ROSWELL CITY-T1	UNATTENDED DISTRIB	115.00	13.20	
14	ROSWELL CITY-T2	UNATTENDED DISTRIB	115.00	13.20	
15	ROSWELL-T1	UNATTENDED TRANSM	115.00	69.00	13.20
16	ROSWELL-T2	UNATTENDED TRANSM	115.00	69.00	13.20
17	ROUND UP-T1S,T1N,T1	UNATTENDED DISTRIB	13.20	2.40	
18	ROXANNA-T1	UNATTENDED DISTRIB	69.00	13.20	
19	RUSSELL POOL-T1	UNATTENDED DISTRIB	115.00	12.50	
20	RUSSELL POOL-T2	UNATTENDED DISTRIB	115.00	13.20	
21	SAGE BRUSH-T1	UNATTENDED DISTRIB	115.00	23.00	
22	SAMSON-T1	UNATTENDED DISTRIB	115.00	12.50	
23	SAN JACINTO-T1S,T1N,T1	UNATTENDED DISTRIB	13.20	2.40	
24	SAND DUNES-T1	UNATTENDED DISTRIB	115.00	13.20	
25	SEAGRAVES INTERCHANGE-T1	UNATTENDED TRANSM	115.00	69.00	13.20
26	SEMINOLE CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
27	SEMINOLE INTG-T1	UNATTENDED TRANSM	230.00	115.00	13.20
28	SEMINOLE INTG-T2	UNATTENDED TRANSM	230.00	115.00	13.20
29	SEMINOLE INTG-T3	UNATTENDED DISTRIB	115.00	23.00	
30	SEVEN RIVERS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
31	SEVEN RIVERS-T2	UNATTENDED TRANSM	230.00	115.00	13.80
32	SHALLOWATER-T1S,T1N,T1	UNATTENDED DISTRIB	23.00	2.40	
33	SHAMROCK PUMP-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	2.40	
34	SHELL C2 COMPRESSOR-T1	UNATTENDED DISTRIB	115.00	4.16	
35	SHELL C3-T1	UNATTENDED DISTRIB	115.00	12.50	
36	SHERMAN COUNTY-T1	UNATTENDED DISTRIB	115.00	34.50	
37	SILVERTON CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
38	SLATON-T1	UNATTENDED DISTRIB	69.00	23.00	
39	SLATON-T2	UNATTENDED DISTRIB	69.00	4.16	
40	SLAUGHTER-T1	UNATTENDED DISTRIB	69.00	2.40	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SMITH-T1	UNATTENDED DISTRIB	69.00	4.16	
2	SNEED-T1	UNATTENDED DISTRIB	34.50	12.50	
3	SONCY-T1	UNATTENDED DISTRIB	69.00	13.80	
4	SOUTH GEORGIA-T1	UNATTENDED TRANSM	115.00	69.00	
5	SOUTH GEORGIA-T2	UNATTENDED DISTRIB	115.00	13.80	
6	SOUTH GEORGIA-T3	UNATTENDED DISTRIB	115.00	12.50	
7	SOUTH PLAINS-T1W,T1E,T1	UNATTENDED DISTRIB	23.00	4.16	
8	SOUTHEAST-T1	UNATTENDED DISTRIB	115.00	13.20	
9	SOUTHLAND-T1S,T1N,T1	UNATTENDED DISTRIB	69.00	2.40	
10	SPEARMAN CITY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
11	SPEARMAN CITY-T2	UNATTENDED DISTRIB	115.00	4.16	
12	SPEARMAN INTG-T1	UNATTENDED TRANSM	115.00	69.00	13.20
13	SPEARMAN INTG-T2	UNATTENDED DISTRIB	69.00	34.50	
14	SPRING CREEK-T1	UNATTENDED DISTRIB	69.00	13.80	
15	SPRING DRAW-T1	UNATTENDED DISTRIB	115.00	13.20	
16	SPRINGLAKE-T1	UNATTENDED DISTRIB	69.00	12.50	
17	STINNETT-T1	UNATTENDED DISTRIB	34.50	12.50	
18	STRATA-T1	UNATTENDED DISTRIB	69.00	12.50	
19	STRATFORD-T1	UNATTENDED DISTRIB	34.50	2.40	
20	STRATFORD-T2	UNATTENDED DISTRIB	34.50	12.50	
21	SUDAN RURAL-T1	UNATTENDED DISTRIB	69.00	12.50	
22	SULPHUR SPRINGS-T1	UNATTENDED TRANSM	115.00	69.00	13.20
23	SULPHUR SPRINGS-T2	UNATTENDED TRANSM	115.00	69.00	13.20
24	SUNDOWN-T1	UNATTENDED TRANSM	230.00	115.00	13.20
25	SUNRAY-T1W,T1E,T1	UNATTENDED DISTRIB	34.50	7.20	
26	SUNSET-T1	UNATTENDED DISTRIB	115.00	13.20	
27	SUNSET-T2	UNATTENDED DISTRIB	115.00	13.20	
28	SWISHER COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
29	TAHOKA CITY-T1	UNATTENDED DISTRIB	23.00	2.40	
30	TASCOSA-T1	UNATTENDED DISTRIB	34.50	13.20	
31	TEAGUE-T1	UNATTENDED DISTRIB	115.00	12.50	
32	TENNECO-T1	UNATTENDED DISTRIB	69.00	12.50	
33	TERRY COUNTY-T1	UNATTENDED TRANSM	115.00	69.00	13.20
34	TERRY COUNTY-T2	UNATTENDED TRANSM	115.00	69.00	13.20
35	TEXACO-T1	UNATTENDED DISTRIB	69.00	12.50	
36	TEXAS FARMS-T1	UNATTENDED DISTRIB	115.00	13.20	
37	TOKIO-T1	UNATTENDED DISTRIB	69.00	12.50	
38	TOLK-T1	UNATTENDED TRANSM	345.00	230.00	13.20
39	TUCO-T1	UNATTENDED TRANSM	345.00	230.00	13.20
40	TUCO-T12	UNATTENDED TRANSM	115.00	69.00	13.20

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TUCO-T2	UNATTENDED TRANSM	230.00	115.00	13.20
2	TUCO-T3	UNATTENDED TRANSM	115.00	69.00	13.20
3	TUCO-T4	UNATTENDED TRANSM	115.00	69.00	13.20
4	TUCO-T5	UNATTENDED DISTRIB	69.00	12.50	
5	TUCO-T6 SVC	UNATTENDED DISTRIB	230.00	13.20	
6	TUCO-T7	UNATTENDED TRANSM	230.00	115.00	
7	TUCO-T8	UNATTENDED TRANSM	345.00	230.00	13.20
8	TWEEDY-T1	UNATTENDED DISTRIB	115.00	13.20	
9	UNITED SALT-T1	UNATTENDED DISTRIB	69.00	12.50	
10	URTON-T1	UNATTENDED DISTRIB	115.00	13.20	
11	VAN BUREN-T1	UNATTENDED DISTRIB	69.00	13.20	
12	VAN BUREN-T2	UNATTENDED DISTRIB	69.00	13.20	
13	VEGA-T1	UNATTENDED DISTRIB	69.00	13.20	
14	VICKERS-T1	UNATTENDED DISTRIB	69.00	23.00	
15	WADE-T1	UNATTENDED DISTRIB	115.00	13.20	
16	WARD-T1	UNATTENDED DISTRIB	115.00	12.50	
17	WASSON-T1	UNATTENDED DISTRIB	69.00	2.40	
18	WAVERLY-T1	UNATTENDED DISTRIB	23.00	4.16	
19	WEATHERLY-T1	UNATTENDED DISTRIB	69.00	13.80	
20	WELLMAN-T1	UNATTENDED DISTRIB	69.00	12.50	
21	WEST BENDER-T1	UNATTENDED DISTRIB	115.00	7.20	
22	WHEELER COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
23	WHITAKER-T1	UNATTENDED DISTRIB	115.00	13.80	
24	WHITE CITY-T1	UNATTENDED DISTRIB	7.20	2.40	
25	WHITEFACE-T1	UNATTENDED DISTRIB	69.00	12.50	
26	WHITEHEAD-T1	UNATTENDED DISTRIB	69.00	4.16	
27	WHITHARREL-T1	UNATTENDED DISTRIB	69.00	4.16	
28	WHITTEN-T1	UNATTENDED DISTRIB	115.00	12.50	
29	WILDORADO-T1	UNATTENDED DISTRIB	69.00	12.50	
30	WILLS OIL-T1E, T1	UNATTENDED DISTRIB	69.00	7.20	
31	WILLS OIL-T1W	UNATTENDED DISTRIB	69.00	12.50	
32	WILSON-T1	UNATTENDED DISTRIB	23.00	2.40	
33	WIPP-T1	UNATTENDED DISTRIB	115.00	13.80	
34	WIPP-T2	UNATTENDED DISTRIB	115.00	13.80	
35	WOLFFORTH-T1	UNATTENDED TRANSM	230.00	115.00	13.20
36	WOODDRAW-T1	UNATTENDED DISTRIB	115.00	13.20	
37	XIT-T1	UNATTENDED TRANSM	230.00	115.00	13.20
38	YANCY-T1	UNATTENDED DISTRIB	69.00	2.40	
39	YOAKUM COUNTY-T1	UNATTENDED TRANSM	230.00	115.00	13.20
40	YOAKUM COUNTY-T2	UNATTENDED TRANSM	230.00	115.00	13.20

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1	ZAVALLA-T1	UNATTENDED DISTRIB	69.00	12.50	
2	ZIA-T1	UNATTENDED DISTRIB	115.00	13.20	
3	522				
4					
5	Count TTL Transformer Banks	522			
6	Count TTL Transformers In Service	593			
7	TTL MVA In Service	27,666			
8	Count TTL Substations with Transformers	387			
9	Count TTL Substations without Transformers	65			
10	Count TTL Substations	452			
11	Count TTL Spares	39			
12					
13					
14	Spare Transformers				
15	10 MVA MOBILE-T1	N/A	69.00	13.20	
16	16 MVA MOBILE-T1	N/A	69.00	12.50	
17	20 MVA NEW MOBILE-T1	N/A	115.00	25.00	
18	20 MVA OLD MOBILE-T1	N/A	115.00	25.00	
19	3 MVA MOBILE-T1	N/A	25.00	12.50	
20	56 MVA MOBILE	N/A	115.00	69.00	13.20
21	Booker-S490008	N/A	69.00	35.00	
22	Chaves-	N/A	230.00	115.00	
23	Clovis Yard-	N/A	69.00	5.00	
24	Clovis Yard-SHT-5301-0101	N/A	69.00	5.00	
25	EAST PLANT-201741	N/A	115.00	5.00	
26	EAST PLANT-207971	N/A	69.00	35.00	
27	EAST PLANT-2720511	N/A	35.00	13.00	
28	EAST PLANT-3461025	N/A	35.00	13.00	
29	EAST PLANT-58224618211	N/A	115.00	14.00	
30	EAST PLANT-6151201	N/A	69.00	13.00	
31	EAST PLANT-6352677	N/A	14.00	2.50	
32	EAST PLANT-7018874	N/A	13.00	5.00	
33	EAST PLANT-86201	N/A	35.00	13.00	
34	EAST PLANT-9405401326	N/A	69.00	35.00	
35	EAST PLANT-C4234411	N/A	69.00	5.00	
36	EAST PLANT-C500502	N/A	69.00	25.00	
37	EAST PLANT-M16218813	N/A	69.00	13.00	
38	FOLLETT-3330738	N/A	35.00	7.50	
39	Harrington Poleyard-5352PH099	N/A	230.00	115.00	13.00
40	Harrington Poleyard-8727009	N/A	345.00	230.00	

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1	Harrington Poleyard-E4468	N/A	115.00	69.00	13.00
2	Harrington Poleyard-E4469	N/A	115.00	69.00	13.00
3	Hobbs Gen-LLL5856-2	N/A	230.00	138.00	13.00
4	Navajo #4 Yard- B313935	N/A	69.00	5.00	
5	North Subs Opns-	N/A	35.00	5.00	
6	North Subs Opns-	N/A	25.00	5.00	
7	North Subs Opns-	N/A	14.00	5.00	
8	Plainview City-8976856	N/A	69.00	2.50	
9	RIVERVIEW PLANT-1699300	N/A	14.00	2.50	
10	RIVERVIEW PLANT-26038-1	N/A	13.00	2.50	
11	RIVERVIEW PLANT-921156	N/A	35.00	13.00	
12	RIVERVIEW PLANT-C-859906	N/A	35.00	2.50	
13	XFMR SPARE (RoadRunner)	N/A	345.00	115.00	
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	3					1
37	1					2
3	1					3
3	1					4
3	1					5
14	1					6
13	1					7
11	1					8
3	1					9
11	1					10
22	1					11
252	1					12
8	1					13
4	1					14
3	1					15
168	1					16
168	1					17
2	1					18
28	1					19
28	1					20
11	1					21
5	1					22
13	1					23
14	1					24
40	1					25
40	1					26
1	3					27
40	1					28
3	1					29
1	1					30
1	1					31
1	1					32
50	1					33
50	1					34
1	1					35
3	1					36
50	1					37
50	1					38
17	1					39
75	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
75	1					1
3	1					2
224	1					3
4	1					4
1	1					5
	1					6
8	1					7
4	1					8
5	1					9
4	1					10
28	1					11
84	1					12
84	1					13
84	1					14
28	1					15
3	1					16
6	1					17
13	1					18
13	1					19
11	1					20
150	1					21
28	1					22
14	1					23
7	1					24
11	1					25
28	1					26
28	1					27
13	1					28
	1					29
28	1					30
28	1					31
28	1					32
168	1					33
40	1					34
20	1					35
	3					36
4	1					37
40	1					38
40	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
13	1					1
75	1					2
75	1					3
1	3					4
25	1					5
28	1					6
28	1					7
250	1					8
252	1					9
44	1					10
28	1					11
110	1					12
28	1					13
28	1					14
11	1					15
1	3					16
6	1					17
28	1					18
25	1					19
6	1					20
28	1					21
22	1					22
14	1					23
28	1					24
40	1					25
40	1					26
	3					27
22	1					28
14	1					29
5	1					30
14	1					31
25	1					32
75	1					33
19	1					34
84	1					35
8	1					36
4	1					37
25	1					38
5	1					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
84	1					2
40	1					3
6	1					4
20	1					5
	1					6
20	1					7
44	1					8
40	1					9
5	1					10
40	1					11
22	1					12
9	1					13
40	1					14
10	1					15
5	1					16
	3					17
9	1					18
250	1					19
168	1					20
8	1					21
13	1					22
50	1					23
50	1					24
4	1					25
4	1					26
67	1					27
1	3					28
20	1					29
14	1					30
22	1					31
22	1					32
20	1					33
50	1					34
22	1					35
20	1					36
28	1					37
6	1					38
4	1					39
6	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
40	1					2
28	1					3
252	1					4
84	1					5
84	1					6
2	3					7
22	1					8
168	1					9
100	1					10
560	1					11
250	1					12
13	1					13
	3					14
8	1					15
28	1					16
28	1					17
20	1					18
25	1					19
28	1					20
13	1					21
11	1					22
28	1					23
3	1					24
28	1					25
11	1					26
84	1					27
75	1					28
1	3					29
1	3					30
1	1					31
6	1					32
1	2					33
3	1					34
20	1					35
25	1					36
40	1					37
40	1					38
6	1					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
1	3					2
84	1					3
84	1					4
250	1					5
250	1					6
75	1					7
2	1					8
4	1					9
2	1					10
4	1					11
15	1					12
40	1					13
40	1					14
6	1					15
84	1					16
84	1					17
1	3					18
14	1					19
28	1					20
13	1					21
20	1					22
84	1					23
84	1					24
40	1					25
40	1					26
17	1					27
28	1					28
2	3					29
47	1					30
560	1					31
250	1					32
560	1					33
150	1					34
200	1					35
28	1					36
22	1					37
28	1					38
22	1					39
22	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2	3					1
84	1					2
84	1					3
28	1					4
14	1					5
40	1					6
84	1					7
75	1					8
150	1					9
150	1					10
272	1					11
273	1					12
2	1					13
7	1					14
20	1					15
250	1					16
6	1					17
20	1					18
5	1					19
2	3					20
14	1					21
75	1					22
84	1					23
20	1					24
1	3					25
84	1					26
22	1					27
14	1					28
56	1					29
10	1					30
252	1					31
75	1					32
75	1					33
84	1					34
3	1					35
28	1					36
28	1					37
14	1					38
13	1					39
50	1					40

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
22	1					2
2	3					3
2	3					4
22	1					5
28	1					6
7	1					7
1	1					8
8	1					9
1	1					10
1	2					11
28	1					12
3	1					13
14	1					14
3	3					15
3	1					16
2	1					17
28	1					18
150	1					19
84	1					20
84	1					21
252	1					22
84	1					23
250	1					24
40	1					25
27	1					26
14	1					27
20	1					28
3	1					29
14	1					30
13	1					31
6	1					32
25	1					33
13	1					34
11	1					35
25	1					36
9	1					37
5	1					38
4	1					39
14	1					40

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SUBSTATIONS (Continued)

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22	1					1
5	1					2
10	1					3
28	1					4
225	1					5
17	1					6
5	1					7
10	1					8
14	1					9
14	1					10
50	1					11
250	1					12
8	1					13
22	1					14
22	1					15
22	1					16
22	1					17
11	1					18
250	1					19
250	1					20
150	1					21
11	1					22
22	1					23
28	1					24
28	1					25
84	1					26
225	1					27
168	1					28
28	1					29
29	1					30
8	1					31
4	1					32
3	3					33
3	3					34
28	1					35
25	1					36
25	1					37
22	1					38
8	1					39
8	1					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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84	1					1
22	1					2
5	1					3
168	1					4
28	1					5
27	1					6
12	1					7
6	3					8
3	1					9
3	1					10
28	1					11
1	3					12
1	3					13
22	1					14
14	1					15
14	1					16
22	1					17
22	1					18
252	1					19
6	1					20
250	1					21
8	1					22
14	1					23
7	1					24
84	1					25
84	1					26
13	1					27
250	1					28
84	1					29
84	1					30
500	1					31
252	1					32
250	1					33
28	1					34
25	1					35
28	1					36
225	1					37
28	1					38
25	1					39
25	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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3	3					1
225	1					2
250	1					3
8	1					4
25	1					5
40	1					6
250	1					7
448	1					8
50	1					9
6	1					10
250	1					11
252	1					12
28	1					13
28	1					14
40	1					15
40	1					16
	3					17
14	1					18
12	1					19
25	1					20
50	1					21
22	1					22
3	3					23
28	1					24
75	1					25
3	1					26
150	1					27
150	1					28
28	1					29
44	1					30
150	1					31
	3					32
2	3					33
13	1					34
13	1					35
20	1					36
2	1					37
14	1					38
4	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
4	1					2
37	1					3
84	1					4
25	1					5
28	1					6
1	3					7
28	1					8
2	3					9
11	1					10
11	1					11
84	1					12
13	1					13
9	1					14
28	1					15
8	1					16
6	1					17
28	1					18
3	1					19
4	1					20
5	1					21
45	1					22
45	1					23
100	1					24
3	3					25
25	1					26
28	1					27
250	1					28
3	1					29
7	1					30
14	1					31
7	1					32
84	1					33
84	1					34
20	1					35
9	1					36
6	1					37
560	1					38
560	1					39
84	1					40

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Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
252	1					1
84	1					2
84	1					3
13	1					4
90	1					5
225	1					6
560	1					7
22	1					8
1	1					9
22	1					10
25	1					11
25	1					12
14	1					13
14	1					14
7	1					15
5	1					16
2	1					17
4	1					18
14	1					19
5	1					20
22	1					21
250	1					22
25	1					23
3	1					24
14	1					25
4	1					26
3	1					27
13	1					28
13	1					29
1	2					30
1	1					31
1	1					32
22	1					33
22	1					34
168	1					35
28	1					36
250	1					37
2	1					38
150	1					39
150	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
13	1					1
13	1					2
27666	593					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
10		1				15
16		1				16
20		1				17
20		1				18
3		1				19
56		1				20
8		1				21
150		1				22
4		1				23
7		1				24
6		1				25
20		1				26
11		1				27
5		1				28
20		1				29
6		1				30
3		1				31
4		1				32
1		1				33
6		1				34
8		1				35
6		1				36
28		1				37
		1				38
250		1				39
560		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
84		1				1
84		1				2
150		1				3
5		1				4
4		1				5
4		1				6
4		1				7
1		1				8
2		1				9
2		1				10
3		1				11
2		1				12
448		1				13
						14
						15
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						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/02/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Services provided by Xcel Energy Services, Inc.	Xcel Energy Services Inc.	See Footnote	
3				
4				
5				
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services	233	-296,000,000
7	Repayments from Utility Money Pool Arrangement	Xcel energy Services	145	-133,000,000
8	Capital Contributions from Parent	Xcel Energy, Inc.	207	-426,232,000
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23	Investment in Utility Money Pool Arrangement	Xcel Energy Services	145	133,000,000
24	Repayment under Utility Money Pool Arrangement	Xcel Energy Services	233	296,000,000
25	Dividends on Common Stock	Xcel Energy, Inc.	438	332,687,725
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: c

Service Function Group	Updated FERC Group	Total
Accounting, Financial Reporting & Taxes	107-108 CWIP and Accum Dep	24,031
	181-190-Deferred Debits	1,060
	408-409-Taxes	342,624
	417-421-Other Income	(766,850)
	426.1-426.5-Other Income Deductions	(3,495)
	427-432-Interest Charges	19,451
	500-514-Steam Power Generation	259,585
	546-557-Other Power Generation	41,300
	560-573-Transmission Expenses	2,365
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	12,285
	901-905-Customer Accounts Expenses	(73,549)
	908-910-Customer Service and Informational Expenses	(293)
	920-935-Administrative and General Expense	14,605,641
Accounting, Financial Reporting & Taxes Total		14,464,159
Aviation Services	408-409-Taxes	9,963
	426.1-426.5-Other Income Deductions	83
	920-935-Administrative and General Expense	703,203
Aviation Services Total		713,249
Business Systems	107-108 CWIP and Accum Dep	22,487,614
	181-190-Deferred Debits	1,295
	408-409-Taxes	551,263
	417-421-Other Income	828
	426.1-426.5-Other Income Deductions	19,832
	500-514-Steam Power Generation	702,593
	546-557-Other Power Generation	665,959
	560-573-Transmission Expenses	2,385,979
	580-598-Distribution Expenses	862,062
	901-905-Customer Accounts Expenses	2,785,413
	920-935-Administrative and General Expense	35,496,052
Business Systems Total		65,958,890
Claims Services	408-409-Taxes	8,249
	920-935-Administrative and General Expense	185,873
Claims Services Total		194,122
Corporate Communications	181-190-Deferred Debits	39,654
	408-409-Taxes	44,880
	426.1-426.5-Other Income Deductions	5,872
	560-573-Transmission Expenses	362
	580-598-Distribution Expenses	1,013
	901-905-Customer Accounts Expenses	361
	908-910-Customer Service and Informational Expenses	63,450
	920-935-Administrative and General Expense	1,286,692
Corporate Communications Total		1,442,284

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Corporate Strategy & Business Development	408-409-Taxes	16,608
	426.1-426.5-Other Income Deductions	10,290
	908-910-Customer Service and Informational Expenses	585
	920-935-Administrative and General Expense	307,750
Corporate Strategy & Business Development Total		335,233
Customer Service	107-108 CWIP and Accum Dep	6,039
	181-190-Deferred Debits	161,830
	408-409-Taxes	172,035
	417-421-Other Income	11,901
	426.1-426.5-Other Income Deductions	1,614
	580-598-Distribution Expenses	2,745
	901-905-Customer Accounts Expenses	3,005,651
	908-910-Customer Service and Informational Expenses	78,559
	920-935-Administrative and General Expense	591,893
Customer Service Total		4,032,266
Employee Communications	408-409-Taxes	4,888
	920-935-Administrative and General Expense	90,581
Employee Communications Total		95,469
Energy Delivery - Engineering/Design	107-108 CWIP and Accum Dep	22,163,505
	181-190-Deferred Debits	106,469
	408-409-Taxes	457,799
	417-421-Other Income	(219,085)
	426.1-426.5-Other Income Deductions	14,619
	500-514-Steam Power Generation	161,612
	546-557-Other Power Generation	45,300
	560-573-Transmission Expenses	7,303,370
	575.1-575.8-Regional Market Expenses	124
	580-598-Distribution Expenses	254,548
	901-905-Customer Accounts Expenses	(203,451)
	920-935-Administrative and General Expense	1,406,708
Energy Delivery - Engineering/Design Total		31,491,519
Energy Delivery Construction, Operations & Maintenance (COM)	107-108 CWIP and Accum Dep	970,580
	181-190-Deferred Debits	19,789
	408-409-Taxes	69,980
	426.1-426.5-Other Income Deductions	9,110
	546-557-Other Power Generation	6,196
	560-573-Transmission Expenses	(206,799)
	580-598-Distribution Expenses	1,348,339
	901-905-Customer Accounts Expenses	6,542
	920-935-Administrative and General Expense	1,359,679
Energy Delivery Construction, Operations & Maintenance (COM) Total		3,583,418
Energy Markets - Fuel Procurement	107-108 CWIP and Accum Dep	7,725
	408-409-Taxes	40,433
	417-421-Other Income	9,342

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

	426.1-426.5-Other Income Deductions	125
	500-514-Steam Power Generation	631,078
	546-557-Other Power Generation	46,599
	560-573-Transmission Expenses	751
	920-935-Administrative and General Expense	239,019
Energy Markets - Fuel Procurement Total		975,070
Energy Markets Regulated Trading & Marketing	107-108 CWIP and Accum Dep	10,563
	408-409-Taxes	232,466
	417-421-Other Income	4,611
	426.1-426.5-Other Income Deductions	12,630
	500-514-Steam Power Generation	12,179
	546-557-Other Power Generation	2,947,259
	560-573-Transmission Expenses	119,183
	575.1-575.8-Regional Market Expenses	535,783
	580-598-Distribution Expenses	2,395
	920-935-Administrative and General Expense	1,341,792
Energy Markets Regulated Trading & Marketing Total		5,218,860
Energy Supply Business Resources	107-108 CWIP and Accum Dep	1,018,378
	408-409-Taxes	366,543
	426.1-426.5-Other Income Deductions	(19,605)
	500-514-Steam Power Generation	5,585,426
	546-557-Other Power Generation	686,772
	560-573-Transmission Expenses	43,620
	580-598-Distribution Expenses	21,538
	901-905-Customer Accounts Expenses	15,564
	908-910-Customer Service and Informational Expenses	1,912
	911-916-Sales Expense	142
	920-935-Administrative and General Expense	1,720,275
Energy Supply Business Resources Total		9,440,565
Energy Supply Engineering & Environmental	107-108 CWIP and Accum Dep	7,407,489
	231-245-Current and Accrued Liabilities	11,052
	408-409-Taxes	285,106
	426.1-426.5-Other Income Deductions	190
	500-514-Steam Power Generation	2,378,090
	546-557-Other Power Generation	108,478
	560-573-Transmission Expenses	21,062
	580-598-Distribution Expenses	33,593
	908-910-Customer Service and Informational Expenses	67
	920-935-Administrative and General Expense	1,709,068
Energy Supply Engineering & Environmental Total		11,954,194
Executive Management Services	107-108 CWIP and Accum Dep	81,672
	130-176-Current and Accrued Assets	3,013
	181-190-Deferred Debits	8,289
	408-409-Taxes	46,256

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/02/2020	2019/Q4

FOOTNOTE DATA

	417-421-Other Income	(73)
	426.1-426.5-Other Income Deductions	1,072,031
	500-514-Steam Power Generation	(252,525)
	546-557-Other Power Generation	(27,546)
	560-573-Transmission Expenses	(86,196)
	575.1-575.8-Regional Market Expenses	(2,361)
	580-598-Distribution Expenses	(94,363)
	908-910-Customer Service and Informational Expenses	874
	911-916-Sales Expense	71
	920-935-Administrative and General Expense	1,863,209
Executive Management Services Total		2,612,350
Facilities & Real Estate	107-108 CWIP and Accum Dep	726,388
	408-409-Taxes	55,630
	417-421-Other Income	2,199
	426.1-426.5-Other Income Deductions	25,361
	500-514-Steam Power Generation	4,078,994
	546-557-Other Power Generation	443,992
	560-573-Transmission Expenses	1,611,821
	575.1-575.8-Regional Market Expenses	44,147
	580-598-Distribution Expenses	1,794,636
	901-905-Customer Accounts Expenses	88
	908-910-Customer Service and Informational Expenses	13
	911-916-Sales Expense	1
	920-935-Administrative and General Expense	5,528,127
Facilities & Real Estate Total		14,311,396
Finance & Treasury	107-108 CWIP and Accum Dep	(2,355)
	181-190-Deferred Debits	926,777
	231-245-Current and Accrued Liabilities	148,929
	408-409-Taxes	92,460
	417-421-Other Income	(384,883)
	426.1-426.5-Other Income Deductions	28,137
	427-432-Interest Charges	757,813
	500-514-Steam Power Generation	6,335
	546-557-Other Power Generation	273,252
	575.1-575.8-Regional Market Expenses	1,968
	580-598-Distribution Expenses	95
	901-905-Customer Accounts Expenses	1,067
	908-910-Customer Service and Informational Expenses	174
	920-935-Administrative and General Expense	3,924,684
Finance & Treasury Total		5,774,454
Fleet	107-108 CWIP and Accum Dep	105,722
Fleet Total		105,722
Government Affairs	107-108 CWIP and Accum Dep	(74)
	408-409-Taxes	21,253
	426.1-426.5-Other Income Deductions	189,728
	911-916-Sales Expense	6

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

	920-935-Administrative and General Expense	349,789
Government Affairs Total		560,702
Human Resources	107-108 CWIP and Accum Dep	53,009
	181-190-Deferred Debits	(27)
	227-230-Other Noncurrent Liabilities	652,557
	231-245-Current and Accrued Liabilities	2,289,276
	408-409-Taxes	236,864
	426.1-426.5-Other Income Deductions	14,365
	500-514-Steam Power Generation	167,003
	546-557-Other Power Generation	8,683
	560-573-Transmission Expenses	251,454
	580-598-Distribution Expenses	349,944
	908-910-Customer Service and Informational Expenses	31,035
	920-935-Administrative and General Expense	3,679,346
Human Resources Total		7,733,511
Internal Audit	408-409-Taxes	20,401
	426.1-426.5-Other Income Deductions	117
	920-935-Administrative and General Expense	431,642
Internal Audit Total		452,160
Investor Relations	408-409-Taxes	4,744
	426.1-426.5-Other Income Deductions	386
	920-935-Administrative and General Expense	279,762
Investor Relations Total		284,892
Legal	107-108 CWIP and Accum Dep	61,154
	408-409-Taxes	115,738
	417-421-Other Income	1,966
	426.1-426.5-Other Income Deductions	971
	500-514-Steam Power Generation	6
	546-557-Other Power Generation	3,292
	560-573-Transmission Expenses	67,756
	580-598-Distribution Expenses	11
	920-935-Administrative and General Expense	2,344,309
Legal Total		2,595,202
Marketing & Sales	107-108 CWIP and Accum Dep	175,094
	181-190-Deferred Debits	1,195,230
	408-409-Taxes	29,376
	417-421-Other Income	21,892
	426.1-426.5-Other Income Deductions	1,270
	901-905-Customer Accounts Expenses	136
	908-910-Customer Service and Informational Expenses	99,728
	920-935-Administrative and General Expense	1,874,116
Marketing & Sales Total		3,396,842
Payment & Reporting	107-108 CWIP and Accum Dep	2,840
	408-409-Taxes	9,170
	920-935-Administrative and General Expense	221,194

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southwestern Public Service Company	(1) X An Original (2) __ A Resubmission	04/02/2020	2019/Q4

FOOTNOTE DATA

Payment & Reporting Total		233,204
Payroll	408-409-Taxes	16,404
	426.1-426.5-Other Income Deductions	37
	920-935-Administrative and General Expense	300,312
Payroll Total		316,753
Rates & Regulation	107-108 CWIP and Accum Dep	4,492
	181-190-Deferred Debits	818,149
	408-409-Taxes	86,520
	426.1-426.5-Other Income Deductions	(34)
	901-905-Customer Accounts Expenses	230
	920-935-Administrative and General Expense	1,705,594
Rates & Regulation Total		2,614,950
Receipts Processing	408-409-Taxes	20,508
	426.1-426.5-Other Income Deductions	828
	560-573-Transmission Expenses	578
	901-905-Customer Accounts Expenses	78,535
	920-935-Administrative and General Expense	163,488
Receipts Processing Total		263,937
Supply Chain	107-108 CWIP and Accum Dep	398,082
	181-190-Deferred Debits	369
	231-245-Current and Accrued Liabilities	(2,443)
	408-409-Taxes	1,410
	417-421-Other Income	(7)
	426.1-426.5-Other Income Deductions	8,245
	500-514-Steam Power Generation	2,119
	546-557-Other Power Generation	82,175
	560-573-Transmission Expenses	1,375
	580-598-Distribution Expenses	45,318
	901-905-Customer Accounts Expenses	4,509
	908-910-Customer Service and Informational Expenses	611
	911-916-Sales Expense	39
	920-935-Administrative and General Expense	290,427
Supply Chain Total		832,230
Grand Total		191,987,601

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INDEPENDENT ACCOUNTANTS' REVIEW REPORT

To the Board of Directors of
Southwestern Public Service Company
Amarillo, Texas

We have reviewed the historical dollar amounts included in rate schedules A-5, B-1, B-2, B-3, B-4, B-5, B-6, C-1, E-2, E-3, E-4, F-1, G-1, G-3, G-4, G-5, G-6, G-8, G-9, H-1, H-2, H-4, H-5, H-7, H-8, H-9, H-10, H-11, H-12, H-13, H-14, H-15, I-1, I-2, I-3, P-2, P-3, and P-4 (the "Schedules"), in the Rate Filing Package of Southwestern Public Service Company ("SPS") as of and for the 12 months ended September 30, 2020, submitted pursuant to Rule 530 of the New Mexico Public Regulation Commission ("NMPRC"). SPS' management is responsible for the Schedules. Our responsibility is to express a conclusion on the Schedules based on our review.

Our review was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the review to obtain limited assurance about whether any material modifications should be made to the Schedules in order for them to be in accordance with the criteria. A review is substantially less in scope than an examination, the objective of which is to obtain reasonable assurance about whether the Schedules are in accordance with the criteria, in all material respects, in order to express an opinion. Accordingly, we do not express such an opinion. We believe that our review provides a reasonable basis for our conclusion.

Our review procedures did not extend to adjustments, estimated amounts, non-accounting, or non-financial information included in the Schedules, and accordingly, we do not express an opinion or any other form of assurance on such information.

Based on our review, we are not aware of any material modifications that should be made to the Schedules in order for them to be in accordance with Rule 530 prescribed by the NMPRC.

This report is intended solely for the information and use of the management and Board of Directors of SPS and the NMPRC, pursuant to Rule 530, and is not intended to be, and should not be, used by anyone other than the specified parties.

Deloitte & Touche LLP

December 23, 2020