

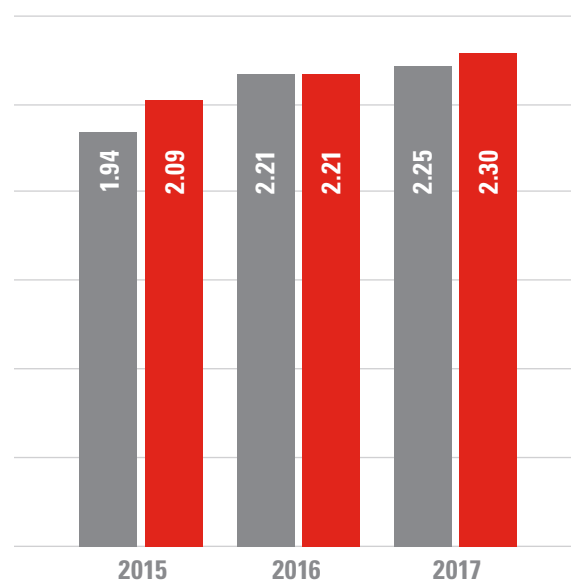


LEADING THE ENERGY FUTURE
ANNUAL **REPORT**

2017

Dollars per share (diluted)

	2016	2017
Total GAAP earnings per share	2.21	2.25
Ongoing earnings per share	2.21	2.30
Dividends annualized	1.36	1.44
Stock price (close)	40.70	48.11
Assets (millions)	41,155	43,030
Book value per common share	21.73	22.56



■ 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 Form 10-K.

Company description

Xcel Energy is a major U.S. electric and natural gas company with annual revenues of \$11.4 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.

On the cover

A drone was used to capture a close-up of one of our company-owned wind farms. Xcel Energy took its Steel for Fuel growth strategy to another level in 2017 by proposing the largest multi-state wind investment in the country. We now have a dozen wind farms in various stages of development.



Some sections in this annual report, including the letter to shareholders, contain forward-looking statements. For a discussion of factors that could affect operating results, please see management's discussion and analysis listed in the table of contents of the Form 10-K.

Dear Fellow Shareholders:

I am proud of the advancements we have made to lead the clean energy transition while we continue to deliver excellent reliability and tremendous value for our customers. Xcel Energy's forward-looking strategy positions us well for short- and long-term success.

From a financial, operational and strategic perspective, 2017 was a strong year for Xcel Energy. In addition to delivering safe, clean, reliable energy to millions of customers, we kept bills low, enhanced the customer experience and once again delivered significant shareholder value. Our one-year Total Shareholder Return of 22 percent in 2017 easily outpaced our peer group average of 9 percent.

For the 13th consecutive year, we met or exceeded our earnings guidance. We delivered 2017 GAAP earnings of \$2.25 per share, compared to \$2.21 per share in 2016, and ongoing earnings of \$2.30 per share, compared to \$2.21 per share in 2016.

Xcel Energy also increased your dividend 5.9 percent in 2017, marking the 14th consecutive year of dividend growth. We maintained our dividend growth guidance in the 5 to 7 percent range, a reflection of our confidence to deliver in 2018 and beyond.

In late 2017, Congress passed major tax reform legislation for the first time in 30 years. Tax reform will help lower our customers' energy bills and, over time, enable us to invest more in our gas and electric system, boosting our earnings power while providing our customers with better energy service. While we see tax reform as positive in the long term, it has an immediate impact on our credit ratings, a challenge faced by most regulated utilities. We are working with our regulators to develop implementation plans that balance protection of our credit rating with customer benefit.

Tax reform also required us to take a one-time charge to EPS of \$0.05 per share in 2017. Despite these challenges, I am very pleased with the outcome of the tax reform debate in Washington. Through our hard work with other companies in our industry, we were able to preserve interest deductibility and help to ensure that the final tax reform legislation will be positive for both our customers and our company.

Holding the line on costs — 2017 was the third consecutive year that O&M expenses have decreased — contributed to solid earnings growth. We expect our strong momentum to continue as we initiated 2018 earnings guidance of \$2.37 to \$2.47 per share.



Leading the Energy Future

We chose the theme “Leading the Energy Future” for this report because it encapsulates our track record of reducing carbon emissions as we successfully transition from fossil fuels to renewable energy and delivering more energy options for our customers — all while keeping bills at or below the rate of inflation.

In 2017, we announced the largest multi-state wind expansion in the country. Our proposal to add 12 wind farms across seven states is the latest example of how we continue to execute our Steel for Fuel growth strategy that delivers economic and environmental benefits. As we add more intermittent wind generation to our system, our engineers and operators have employed advanced technologies and new operating strategies that enable us to do so reliably. Our customers appreciate energy service that is both clean and reliable.

The ability to develop such a large wind proposal in a short time frame was significant because it secured the full production tax credit before it begins to expire — helping to keep customers' bills low. In addition to the projects that were approved, we are also asking for approval to move forward with Dakota Range, the first wind project expected to come online under the phasedown of the federal tax credit, taking advantage of ever-improving technologies and driving continued efficiencies.

Steel for Fuel is a strategy that has strong appeal with all of our stakeholders. Wind energy is a key factor in Xcel Energy's 35 percent reduction in carbon emissions since

2005. Our goal is to reduce carbon emissions 60 percent by 2030 — and we have aspirations to do even more. We are engaging with stakeholders to make this aspiration a reality.

Investing in wind also provides tremendous economic value to our customers because there are no fuel charges. With wind energy at historic low prices and continued technological advancements, we can secure savings that will benefit customers now and for decades to come.

Enhancing the customer experience

In 2017, we not only set a record for power plant reliability across our eight-state territory, but also significantly improved how we communicate with customers during outages. We created a new storm center on our website and launched an award-winning mobile app that was downloaded more than 160,000 times, exceeding expectations. These efforts clearly paid off as the perception of our outage communications leapt over almost 20 of our industry peers.

Foundational work began on our Advanced Grid Intelligence and Security initiative that will upgrade our infrastructure, improve security and reliability and leverage smart meters to provide customers more choices for managing their energy use. The rollout started in Colorado and will extend to Minnesota in subsequent years, pending regulatory approval.

One of the growing threats against the electric grid is the increased sophistication of cyber criminals across the globe.

I am working to help shape national cybersecurity policy through my membership on the National Infrastructure Advisory Council, which advises the President on federal policies that can enhance infrastructure protection. More importantly, we are ever vigilant at home in our efforts to protect our customers and communities, enhancing our security efforts on all levels. One visible example of that effort is the launch of a state-of-the-art Cyber Defense Center that monitors and protects our networks 24 hours a day, seven days a week.

Engaging stakeholders

Through strong stakeholder engagement, we saw greater alignment in regulatory proceedings in nearly all of our jurisdictions. In Minnesota, we received commission approval for a multi-year electric rate case and legislative approval to build a natural gas plant at our Sherco site that will provide needed generation to replace two coal units that are scheduled for early retirement.

We also received Minnesota commission approval for our proposal to exit expensive biomass contracts that were mandated by the state in the 1990s. This innovative solution provided an economic development package for affected communities and will save our customers more than \$600 million by replacing the biomass generation with far-less-costly energy alternatives. By focusing on all aspects of our customers' bills, we continue to find ways to keep energy costs affordable.

CapX2020, the Upper Midwest's renewable energy super highway, is now complete

Without it, the clean energy revolution in the Upper Midwest would not have happened.

CapX2020, a forward-thinking massive transmission project started in 2004 to enhance grid reliability and bring wind energy to customers across the Upper Midwest, is now complete. The 13-year, \$2 billion transmission system upgrade in Minnesota, the Dakotas and Wisconsin was an unprecedented partnership between 11 utility organizations to expand and strengthen the grid and stimulate future renewable energy production.

"If you build it, they will come," said Teresa Mogensen, Senior Vice President, Transmission, noting that nine wind projects and one natural gas generation facility have already requested interconnection to the final CapX2020 section, a 75-mile line that runs parallel to the Minnesota border in eastern South Dakota.

When the final leg of CapX2020 was energized in September 2017, it was the culmination of five individual transmission

projects spanning 800 miles. That's the equivalent of running a single transmission line from Minneapolis, our corporate headquarters, to Amarillo, Texas, the regional headquarters of our Texas and New Mexico operations.

In addition to the safe, clean, reliable energy our customers have come to expect, the CapX2020 project also provided significant economic and environmental benefits. The 3,600 megawatts of wind energy looking to interconnect to two of the CapX2020 transmission lines — enough to power 1.5 million homes — will generate approximately \$15 million in annual landowner royalty payments and will avoid 6.3 million tons of carbon dioxide entering the atmosphere each year.

Looking forward, CapX2020 has the capacity to deliver renewable energy from numerous proposed wind and solar projects across the Upper Midwest.

"Transmission lines and substations are the backbone of the energy grid and a significant driver of economic development," Mogensen said.

While we prepare for our next resource plan, we also engaged the Minnesota commission in dialogue about the importance of operating our nuclear plants through their licensing periods in the early 2030s. As our only 24/7 carbon-free baseload energy source, nuclear energy plays a crucial role in system reliability and our ability to hit aspirational carbon-reduction targets. It's important that we operate our fleet efficiently and effectively, which is exactly what we did in 2017.

In Colorado, we announced a groundbreaking Colorado Energy Plan that, if approved, will drive our carbon-reduction plans by adding significant amounts of wind, solar, natural gas and battery storage while accelerating the retirement of two coal units at our Comanche power plant in Pueblo. If implemented, by 2026 in Colorado we would produce 55 percent of our energy from renewable sources and reduce carbon emissions 60 percent from a 2005 baseline.

Our work engaging with Colorado stakeholders also resulted in approval for an important decoupling rider to encourage customers to save energy, as well as approval of Renewable*Connect, a program that provides residential and business customers a green solution to receive up to 100 percent of their energy from certified renewable sources.

Going forward, we will continue to engage our policymakers and stakeholders to put the benefit of tax reform to work for our customers while supporting the clean energy transition.

Operational excellence

Offering new customer programs is just one way we are focused on enhancing our customers' experience with us. In 2017, we completed a four-year project called "Productivity through Technology" that successfully deployed new software and processes to leverage technology to improve operations and create efficiencies.

We recognize that technology is an important component in our drive to serve customers even better, but it alone is not enough. So at the same time we are undertaking a comprehensive effort to analyze people, processes and technology to drive results and strengthen our underlying culture to be one focused on continuous improvement. This effort generated more than \$30 million in sustainable savings last year due to increased efficiencies and careful management of attrition. We expect an additional \$45 million of savings in 2018 as our efforts continue.

Getting better every day is a mantra embraced by our employees — and it's paying off for customers. At a time when most monthly consumer bills are on the rise, our average residential electric bills across all territories have dropped 3 percent since 2013.

Keeping the public safe is about more than restoring power after storms. Our year-round campaigns to raise awareness about the need to call before you dig to determine the

locations of natural gas lines and underground electric utilities have resulted in our best public safety year on record.

But when storms damage the grid, industry peers agree we are at our best. For the third year in a row, we received an Edison Electrical Institute Emergency Recovery Award for our efforts to restore power following Winter Storm Jupiter, which caused the worst damage to the grid in Texas and New Mexico since 1999. More than 1,000 workers, contractors and mutual aid responders logged 92,000 hours and repaired 7,500 structures.

Our crews, which I believe are the best in the business, raised their hands to help with hurricane recovery efforts. More than 150 full-time employees traveled to Fort Myers, Florida, and spent several long and hot days restoring power to those in need. Another 70 are currently on the ground working to restore power in Puerto Rico, and we'll have supplied a total of 210 employees to that effort over a several-month period.

Xcel Energy employees performed their restoration work quickly and safely. Overall, 2017 was our best safety year ever in terms of the fewest number of employee injuries. Still, we made enhancements to our safety program as we continue our Journey to Zero efforts to promote employee safety, our No. 1 priority.

It starts with employees

The success of Xcel Energy is driven by 11,000 dedicated employees who come to work each and every day to build on the success of this organization. They are the reason that *Forbes* magazine named us one of the World's Top Regarded Companies and one of the World's Best Employers.

Our employees understand the importance of giving back to the communities where they live and work through philanthropy and volunteerism — stocking food shelves, mentoring youth and delivering meals for homebound seniors.

As we look ahead, the employees of Xcel Energy are committed to lead the clean energy transition, enhance the customer experience and keep bills low. If we continue to execute on these three priorities, we will once again deliver short- and long-term value for our customers and shareholders. We appreciate the continued trust you place in us.

Sincerely,



Ben Fowke
Chairman, President and Chief Executive Officer



WIND ENERGY

Investing in our own backyard

When your service territory produces some of the best wind resources in the country, it makes both economic and environmental sense to build in your own backyard.

Xcel Energy took its Steel for Fuel growth strategy to another level in 2017 by proposing the largest multi-state wind investment in the country — a dozen wind farms in seven states. If all the projects are approved as expected, by the end of 2021 Xcel Energy, a national leader in wind energy since 2005, will become the first U.S. utility to surpass 10,000 megawatts of wind capacity.

Steel for Fuel resonates with constituents across the spectrum because it delivers carbon-free renewable energy without raising customer bills — in fact, it saves billions of dollars over the life of the projects because there are no fuel costs. Building and owning wind farms also provides an

attractive organic growth opportunity for shareholders — our proposal will more than quadruple our company-owned wind portfolio.

We are building wind farms throughout our wind-rich service territory — from Upper Midwest farmland through the plains of eastern Colorado to the Texas-New Mexico border. This proposal showcases our ability to move swiftly, taking advantage of the federal production tax credit before it begins to phase down. We subsequently proposed the first project in the country to be completed in 2021 after the phasedown begins, reinforcing the value of wind energy is long lasting.

Building wind farms and the accompanying substations and transmission lines needed to deliver the energy to the marketplace provides a powerful source of economic



In 2017, Xcel Energy proposed the nation's largest multi-state investment in wind energy — a dozen wind farms in seven states expected to be completed by the end of 2021. If all projects are approved, the wind farms will deliver nearly 3,700 megawatts of clean energy, enough to power 1.7 million homes. The vast majority of these wind projects will be company owned, just like the Courtenay Wind Farm (pictured) near Jamestown, North Dakota.

Xcel Energy is developing **12** wind farms that will produce **3,680 MW*** of clean energy:



Upper Midwest

Colorado

Texas/New Mexico

1,850 MW

600 MW

1,230 MW

*Does not include the Colorado Energy Plan

development in rural America. Our multi-state proposal is expected to create 2,700 construction jobs and 150 full-time positions, and generate \$800 million in landowner lease and property tax payments over the lives of the projects.


By 2022, 38 percent of our energy will be supplied by wind — double the amount on our system in 2017. Our proposed wind farms are expected to generate enough clean energy to power 1.7 million homes annually and avoid 142 million tons of carbon emissions over the projects' lifetimes.

The first project to come online will be Rush Creek, a 600-megawatt wind farm in eastern Colorado, the largest in the company's history and the largest in Colorado. When completed in the fall of 2018, there will be enough wind capacity on our system in Colorado to power every home along Colorado's Front Range with 100 percent wind energy.

Colorado Energy Plan

In Colorado, we are not stopping with Rush Creek — we plan to continue the transition from fossil fuels to renewable energy in the coming years. After extensive stakeholder outreach, we proposed the new Colorado Energy Plan, a blueprint for the state's energy future that adds significant amounts of wind, solar, natural gas and energy storage to our system to offset the early retirement of two coal units. The plan received nearly unanimous approval from a wide range of stakeholders.

If approved by the Colorado Public Utilities Commission, we could achieve 55 percent renewable energy on the grid in Colorado and reduce carbon emissions 60 percent from 2005 levels by 2026 while saving customers money on their bills.



Gerdau, the largest recycler in the state of Minnesota and one of Xcel Energy's largest business customers, melts scrap metal to make 300 grades of high-quality steel products at its facility in St. Paul. Among those products are anchor bolts and jumbo rebar used in wind and transmission tower foundations.

At right: Glowing-hot steel billets emerge from the caster where they will cool and later be refined into high-end steel products. Gerdau invested in a \$65 million state-of-the-art caster to modernize operations at its St. Paul mill. Today the caster produces some of the highest quality steel products in the country.

CUSTOMER FOCUS

Gerdau brings Steel for Fuel full circle

When steel bars emerge from the caster at the Gerdau steel manufacturing plant in St. Paul, the color of the scorching-hot metal is blaze orange. Yet, Gerdau St. Paul Mill's steel products are actually "green."

All of the steel produced at Gerdau's St. Paul steel mill is made from almost 100 percent recycled scrap metals. Every day, a steady stream of trailers brings tons of scrap metal, ranging from end-of-life automobiles to used washing machines. Those materials are shredded, melted in a large electric-arc furnace and converted into steel billets.

After a cooling process, the billets are reheated in a natural gas furnace and further refined into hundreds of high-quality steel products, including anchor bolts and reinforcing rebar used for wind tower foundations for various Xcel Energy construction projects. Many of the plant's by-products have value-added end uses such as slag used in road construction.

Converting scrap metal into steel billets is an energy-intensive process. In two minutes, the plant uses as much energy as an average residential house for a month. Gerdau participates in Xcel Energy's short-notice load management program to save on their energy costs each year while providing reliability and cost-saving benefits to the grid.

"We have a strong working relationship with Xcel Energy. They provide us with the reliability that is essential to run our facility and offer various programs to help manage our energy costs," said Alan Lamb, Gerdau St. Paul Vice President and General Manager. "Xcel Energy understands the importance of keeping energy costs low so their business customers can compete effectively in the global marketplace."

Most steel plants across the country are located in areas with higher carbon emissions from coal plants. Gerdau is a proponent for Xcel Energy's Steel for Fuel efforts to invest



in wind energy, which will lower customer bills and reduce our carbon footprint. In turn, the steel products Gerdau manufactures with our energy have less environmental impact, which is appealing to their customers.

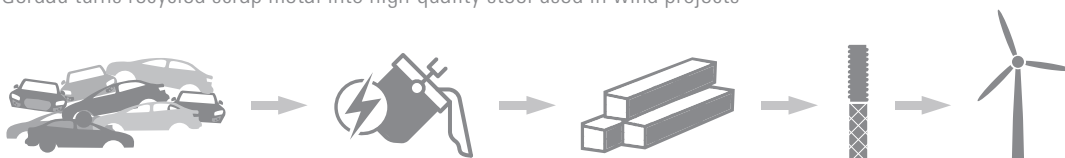
Economic development


Xcel Energy often works behind the scenes to help companies invest in the communities we have the privilege to serve. To modernize its operations, Gerdau decided in 2012 to invest in a \$65 million caster, a significant capital expense required to produce high-quality steel products the marketplace demands.

Xcel Energy partnered with several organizations, including the City of Saint Paul, the St. Paul Port Authority and the Minnesota Chamber of Commerce, to offer an economic development package to ensure Gerdau located the caster at its St. Paul facility instead of another mill. That decision to invest locally helped to safeguard 300 jobs in St. Paul.

“It’s an honor to provide reliable, low-cost and environmentally sound power to support Gerdau and the products they make for the wind industry. It brings the process full circle,” said Xcel Energy Regional Vice President Greg Chamberlain.

Gerdau turns recycled scrap metal into high-quality steel used in wind projects





Eau Claire is the site of Xcel Energy's first community solar garden in Wisconsin, part of the Solar*Connect Community® program. The one-megawatt garden is located across the street from Xcel Energy's Wisconsin headquarters on a seven-acre unused parcel, the site of a former city landfill. Future solar gardens are in development for the greater La Crosse area and Ashland.

At right: Workers install some of the 3,600 panels at a new community solar garden in Eau Claire, Wisconsin.

Below: Dr. Kirk Dahl (right), one of the first community subscribers, tours the site with Mark Stoering, President of Xcel Energy—Wisconsin and Michigan.



COMMUNITY SOLAR GARDENS

Wisconsin customers embrace the sun



Dr. Kirk Dahl jumped at the opportunity to take an advance tour of the newest solar garden in his community.

"I'm proud to be one of the first subscribers for this project — we subscribed at 100 percent," Dr. Dahl, a retired emergency room physician and longtime Eau Claire resident, said while walking among the rows of solar panels. "I've had a lifelong interest in environmental issues and am concerned about climate change. It isn't feasible to place solar panels on our house so this program gave us the opportunity to purchase clean energy in a different way."

Solar*Connect Community is a Wisconsin program paid for entirely by subscribers like Dr. Dahl who subscribe at various levels. Customers pay a one-time fee to purchase energy from the system in exchange for bill credits that vary based on production of all the solar gardens in the



Solar*Connect Community program. The Eau Claire solar garden was energized on October 23, 2017, following a ribbon-cutting ceremony with employees and local leaders. The garden is not only a clean energy success story, but a redevelopment one as well. The garden is located across the street from Xcel Energy's Wisconsin headquarters on an unused seven-acre site that once housed a city landfill.

"This old landfill has a brand new use as a solar array producing green, renewable energy for our community," said Dale Peters, Eau Claire's City Manager. The city of Eau Claire is leasing the land for the project and also participating as a subscriber — purchasing solar energy to power the community pool.

In addition to the solar garden in Eau Claire, a developer has been selected to build a second garden in the greater

La Crosse area in 2018. Xcel Energy also announced a location for a third solar garden in Ashland located adjacent to our Ashland Service Center. With adequate subscriber interest, that garden will be built by mid-2019.

Minnesota is No. 1 in the country

Xcel Energy's community solar program in Minnesota is the largest in the country — by far. At the end of 2017, our Minnesota program had grown to 246 megawatts of energy, which is nearly twice as large as the next largest community solar program. We expect the Minnesota program to double in size as Minnesota customers continue to support this renewable energy option.



ECONOMIC DEVELOPMENT

Regional headquarters spurs downtown revitalization

More than anyone, Paul Harpole knew the struggle to entice businesses to invest in downtown Amarillo. “Our downtown was stagnant,” said Harpole, who served as mayor of the 200,000-person Texas Panhandle community from 2011 until 2017. “It had been decades since we had any new construction downtown.”

That changed in January 2015 when Xcel Energy announced plans to partner with a developer for a new \$42 million facility on the eastern edge of downtown, ensuring the company’s regional headquarters would remain in downtown Amarillo, a tradition that dates back to 1925.

“I look around Amarillo and say, ‘What would this city be without Xcel Energy?’ The company’s vision and forward thinking served as a catalyst to our entire downtown revitalization,” said Harpole, who decided to not seek

reelection in 2017. “Your commitment led to the building of a \$45 million hotel down the street. We just broke ground for a minor league baseball stadium that will open next year. The energy downtown is so exciting.”

David Hudson, President of Xcel Energy–Texas and New Mexico, worked with Mayor Harpole and local leaders on plans to invest in the downtown corridor but also considered other sites in Amarillo. The seven-story facility includes three stories of parking and retail shops on the first floor. Approximately 300 employees work in the regional headquarters, supporting our customers and communities in the Texas Panhandle and eastern New Mexico.

The 790 Buchanan building was completed in May 2017 in time for Xcel Energy to host its Annual Shareholder Meeting, which happened to be one day after Harpole’s



Xcel Energy's decision to pursue a \$42 million regional headquarters on the east side of downtown Amarillo, Texas, is a story that goes well beyond larger floor plans, updated workspaces and improved collaboration opportunities; it was the first major downtown development in years. This project added power to a fledgling downtown revival, one that has matured with a new upscale hotel two blocks away and the recent groundbreaking across the street for a "AA" minor league baseball complex scheduled to open in 2019.

At left: Cars zip past Xcel Energy's new regional headquarters in Amarillo one morning last fall. The 114,000 square-foot building and accompanying parking garage opened in May 2017. Xcel Energy is leasing the space from a real estate investment group through a long-term contract.

mayoral term ended. Incoming mayor Ginger Nelson enjoyed the honor of welcoming Xcel Energy's Board of Directors and shareholders to the city.

"Leadership these days is really about empowering people to do what they are already inspired to do. We are seeing that impact here in Amarillo. We're standing today in this building, and I personally want to thank you for your dedication to our community," Mayor Nelson said.

Hudson noted the important role Xcel Energy plays in driving economic development. "We will only be as successful as the communities we are privileged to serve," Hudson said. "Our No. 1 job is to keep the lights on, but we work very hard at driving economic development through transmission lines and wind farms — projects that directly lead to jobs, tax base and landowner lease payments."

"I look around Amarillo and say, 'What would this city be without Xcel Energy?'"

— Paul Harpole, former Amarillo Mayor

In 2017, 71 percent of our spending — approximately \$2.5 billion — was done at the local level with businesses based in our eight-state service territory. Couple that investment with hundreds of millions in tax payments and it's easy to see how a company that provides two essential but relatively invisible products — electricity and natural gas — can make a visible difference in local communities. Our total base capital expenditure plan includes an investment of at least \$18.5 billion over the next five years.

COMMUNITY INVOLVEMENT

Giving back throughout the year

From cleaning up important riverfront trails to stuffing backpacks with school supplies, Xcel Energy is always delivering in our communities. We live and work here, so we understand the importance of giving back through volunteerism and financial support.

Red Xcel Energy volunteer t-shirts were out in full force in September for our annual Day of Service. In Colorado, a record-setting 700 volunteers packed 155,000 meals for Colorado Feeding Kids. Meanwhile in Minnesota, our volunteers spruced dozens of nonprofit partners, including The Bakken Museum in Minneapolis and Springbrook Nature Center in Fridley.

Across our eight-state service territory, Xcel Energy encourages employee volunteerism through a paid time off program. In 2017, our employees logged approximately 55,000 volunteer hours for charities of their choice.

We also give back to our communities through philanthropy. Our annual United Way campaign — a combination of employee pledges boosted by the company match — will provide a \$4.83 million impact to strengthen our communities. Our foundation also matches employee gifts to eligible nonprofits, resulting in a \$1.29 million impact to more than

1,000 charities. The foundation also donated \$3.45 million in grants to nonprofits that influence positive outcomes in our four focus areas: STEM education, economic sustainability, environmental stewardship and arts and culture.



Above: Tim Warrick watches his son, Brekken, push a load of wood chips at Springbrook Nature Center in Fridley, Minnesota, during our annual Day of Service volunteer event.

MILITARY VETERANS

Company receives Beyond the Yellow Ribbon proclamation

Xcel Energy frequently receives accolades as one of the top military-friendly employers in the industry. In 2017, the State of Minnesota recognized Xcel Energy as a Beyond the Yellow Ribbon company for meeting its criteria as a military veteran employer of choice. Xcel Energy is the eighth Fortune 500 company headquartered in Minnesota to receive the proclamation.

We believe that military veterans bring the values and skills that we need to succeed — leadership, teamwork and dedication. For the third consecutive year, Xcel Energy has achieved its goal that 10 percent of our new external hires are military veterans.

We also understand the importance of offering a welcoming workplace for military veterans and to provide ongoing support for our employees who serve in the National Guard or Reserves. Military Ombudsman for Veterans and Employees (MOVE), our employee resource group focused on development, implementation and communication of programs and policies centered on the welfare of veterans

and their families, celebrated its fifth anniversary in 2017. Our retention of military veterans remains strong and slightly higher than our overall retention numbers. Xcel Energy employs more than 1,200 military veterans.



Above: Xcel Energy CEO Ben Fowke accepts the Beyond the Yellow Ribbon proclamation from the State of Minnesota on behalf of Xcel Energy.

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

(Mark One)

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

For the fiscal year ended December 31, 2017

or

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

Commission File Number: 001-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota

(State or other jurisdiction of incorporation or organization)

41-0448030

(I.R.S. Employer Identification No.)

414 Nicollet Mall

Minneapolis, MN 55401

(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Common Stock, \$2.50 par value per share	Nasdaq Stock Market LLC
Securities registered pursuant to section 12(g) of the Act: None	

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. Large accelerated filer Accelerated filer Non-accelerated filer (Do not check if a smaller reporting company) 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 30, 2017, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was \$23,304,874,235 and there were 507,952,795 shares of common stock outstanding.

As of Feb. 19, 2018, there were 508,064,983 shares of common stock outstanding, \$2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2018 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

Index		
PART I		
Item 1 —	Business	1
	DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS	1
	COMPANY OVERVIEW	5
	ELECTRIC UTILITY OPERATIONS	7
	NSP-Minnesota	7
	NSP-Wisconsin	13
	PSCo	14
	SPS	19
	Summary of Recent Federal Regulatory Developments	23
	Electric Operating Statistics	24
	NATURAL GAS UTILITY OPERATIONS	25
	NSP-Minnesota	26
	NSP-Wisconsin	27
	PSCo	28
	SPS	29
	Natural Gas Operating Statistics	30
	GENERAL	30
	ENVIRONMENTAL MATTERS	31
	CAPITAL SPENDING AND FINANCING	31
	EMPLOYEES	31
	EXECUTIVE OFFICERS	32
Item 1A —	Risk Factors	33
Item 1B —	Unresolved Staff Comments	41
Item 2 —	Properties	42
Item 3 —	Legal Proceedings	45
Item 4 —	Mine Safety Disclosures	45
PART II		
Item 5 —	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	45
Item 6 —	Selected Financial Data	47
Item 7 —	Management’s Discussion and Analysis of Financial Condition and Results of Operations	47
Item 7A —	Quantitative and Qualitative Disclosures About Market Risk	75
Item 8 —	Financial Statements and Supplementary Data	75
Item 9 —	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	144
Item 9A —	Controls and Procedures	144
Item 9B —	Other Information	145
PART III		
Item 10 —	Directors, Executive Officers and Corporate Governance	146
Item 11 —	Executive Compensation	146
Item 12 —	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	146
Item 13 —	Certain Relationships and Related Transactions, and Director Independence	146
Item 14 —	Principal Accountant Fees and Services	146
PART IV		
Item 15 —	Exhibits, Financial Statement Schedules	147
Item 16 —	Form 10-K Summary	159
SIGNATURES	160

PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
NCE	New Century Energies, Inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin.	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo.	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries
XETD	Xcel Energy Transmission Development Company, LLC
XEST	Xcel Energy Southwest Transmission Company, LLC
XEWT	Xcel Energy West Transmission Company, LLC

Federal and State Regulatory Agencies

CFTC	Commodity Futures Trading Commission
CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
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
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
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

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EE	Energy efficiency
EECRF	Energy efficiency cost recovery factor
EIR	Environmental improvement rider (recovers the costs associated with investments in environmental improvements to fossil fuel generation plants)
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 (recovers the costs of certain purchased power costs)
PGA	Purchased gas adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	Renewable energy standard adjustment (recovers the costs of new renewable generation)
PSIA	Pipeline system integrity adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor (recovers transmission infrastructure improvement costs and changes in wholesale transmission charges)
WCA	Windsourc [®] cost adjustment

Other Terms and Abbreviations

AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
C&I	Commercial and Industrial
CAA	Clean Air Act
CACJA	Clean Air Clean Jobs Act
CAIR	Clean Air Interstate Rule
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
CCN	Certificate of convenience and necessity
CIG	Colorado Interstate Gas Company, LLC
CO ₂	Carbon dioxide
CON	Certificate of need

CPCN	Certificate of public convenience and necessity
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CWIP	Construction work in progress
EI	Edison Electric Institute
EGU	Electric generating unit
EPS	Earnings per share
EPU	Extended power uprate
ERCOT	Electric Reliability Council of Texas
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
FTY	Forecast test year
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
Golden Spread	Golden Spread Electric Cooperative, Inc.
HTY	Historic test year
IM	Integrated market
IPP	Independent power producing entities
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
ITC	Investment Tax Credit
LCM	Life cycle management
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
MWTG	Mountain West Transmission Group
NAAQS	National Ambient Air Quality Standard
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NAV	Net asset value
NOL	Net operating loss
NO _x	Nitrogen oxide
NTC	Notifications to construct
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
OCC	Office of Consumer Counsel
OCI	Other comprehensive income
PI	Prairie Island nuclear generating plant
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Purchased power agreement
PRP	Potentially responsible party
PTC	Production tax credit
PV	Photovoltaic
QF	Qualifying facilities
R&E	Research and experimentation
REC	Renewable energy credit

RFP.....	Request for proposal
ROE.....	Return on equity
RPS.....	Renewable portfolio standards
RTO.....	Regional Transmission Organization
SIP.....	State implementation plan
SO ₂	Sulfur dioxide
SPP.....	Southwest Power Pool, Inc.
S&P.....	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
TOs.....	Transmission owners
TransCo.....	Transmission-only subsidiary
TSR.....	Total shareholder return
VIE.....	Variable interest entity

Measurements

Bcf.....	Billion cubic feet
GWh.....	Gigawatt hours
KV.....	Kilovolts
KWh.....	Kilowatt hours
Mcf.....	Thousand cubic feet
MMBtu.....	Million British thermal units
MW.....	Megawatts
MWh.....	Megawatt hours

COMPANY OVERVIEW

Xcel Energy Inc. is a holding company with subsidiaries engaged primarily in the utility business. In 2017, Xcel Energy Inc.'s continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, and serve customers. Along with 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, these companies comprise the regulated utility operations.

Xcel Energy Inc. was incorporated under the laws of Minnesota in 1909. Xcel Energy's executive offices are located at 414 Nicollet Mall, Minneapolis, Minn. 55401. Its 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 public may read and copy any materials that Xcel Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at <http://www.sec.gov>.

NSP-Minnesota

NSP-Minnesota is a utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.5 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 88 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2017 and 2016. Although NSP-Minnesota's large C&I electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large C&I electric sales include: petroleum refining and related industries, food products and health services. For small C&I customers, significant electric retail sales include the following industries: real estate and educational services. Generally, NSP-Minnesota's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System.

The wholesale customers served by NSP-Minnesota comprised approximately 14 percent of its total kWh sold in 2017.

NSP-Minnesota owns the following direct subsidiary: United Power and Land Company, which holds real estate.

NSP-Wisconsin

NSP-Wisconsin is a utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in this service territory. NSP-Wisconsin provides electric utility service to approximately 259,000 customers and natural gas utility service to approximately 114,000 customers. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2017 and 2016. Although NSP-Wisconsin's large C&I electric retail customers are comprised of many diversified industries, a significant portion of NSP-Wisconsin's large C&I electric sales include: food products, paper, allied products and electric, gas and sanitary services. For small C&I customers, significant electric retail sales include the following industries: grocery and dining establishments, educational services and health services. Generally, NSP-Wisconsin's earnings contribute approximately five percent to 10 percent of Xcel Energy's consolidated net income.

The management of the electric generation and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Co., which operates hydro reservoirs; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

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

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

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

SPS

SPS is a utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. SPS provides electric utility service to approximately 390,000 retail customers in Texas and New Mexico. Approximately 71 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2017 and 2016. Although SPS' large C&I electric retail customers are comprised of many diversified industries, a significant portion of SPS' large C&I electric sales include: oil and gas extraction, as well as petroleum refining and related industries. For small C&I customers, significant electric retail sales include the following industries: oil and gas extraction and grocery establishments. Generally, SPS' earnings contribute approximately 10 percent to 15 percent of Xcel Energy's consolidated net income.

The wholesale customers served by SPS comprised approximately 29 percent of its total KWh sold in 2017.

Other Subsidiaries

WGI is a small interstate natural gas pipeline company engaged in transporting natural gas from the PSCo system near Chalk Bluffs, Colo., to Cheyenne, Wyo.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. The gas pipeline and storage facilities are leased under a FERC-approved agreement to CIG.

Xcel Energy Services Inc. is the service company for Xcel Energy Inc.

XETD and XEST are TransCos that will, respectively, participate in MISO and SPP competitive bidding processes for transmission projects. XEWT is a TransCo formed to competitively bid on transmission projects in the western United States.

Xcel Energy Inc.'s nonregulated subsidiaries include Eloigne and Capital Services. Eloigne invests in rental housing projects that qualify for low-income housing tax credits, and Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries.

Xcel Energy conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 17 to the consolidated financial statements for further discussion relating to comparative segment revenues, income from operations and related financial information.

ELECTRIC UTILITY OPERATIONS

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota’s operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC also has regulatory authority over security issuances, property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota’s IRPs for meeting customers’ future energy needs. The MPUC also certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC for its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce. NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and MISO wholesale market. NSP-Minnesota and NSP-Wisconsin are jointly authorized by the FERC to make wholesale electric sales at market-based prices.

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

- *CIP rider* — Recovers the costs of conservation and demand-side management programs.
- *EIR* — Recovers the costs of environmental improvement projects.
- *RDF* — Allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- *RES* — Recovers the cost of renewable generation in Minnesota.
- *RER* — Recovers the cost of renewable generation in North Dakota.
- *SEP* — Recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — Recovers costs associated with investments in electric transmission and distribution grid modernization costs.
- *Infrastructure rider* — Recovers costs for investments in generation and incremental property taxes in South Dakota.

NSP-Minnesota’s retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. In general, capacity costs are recovered through base rates and are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or base rates. In 2017, the MPUC voted to change the process in which utilities seek fuel cost recovery under the FCA in Minnesota to be implemented in July 2019. 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. Monthly variations to the baseline costs would be tracked and netted over a 12-month period. Subsequently, utilities would issue refunds above the baseline costs, and could seek recovery of any overage.

Minnesota state law requires NSP-Minnesota to invest two percent of its state electric revenues and half a percent of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures. Minnesota state law also requires NSP-Minnesota to submit a CIP plan at least every three years.

Capacity and Demand

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

	System Peak Demand (in MW)			
	2017	2016	2015	2018 Forecast
NSP System	8,546	9,002	8,621	9,208

The peak demand for the NSP System typically occurs in the summer. The 2017 system peak demand for the NSP System occurred on July 17, 2017. The decline in peak load from 2016 to 2017 is in part due to considerably cooler weather in 2017. The 2018 forecast assumes normal peak day weather, which is warmer than actual 2017 peak day weather.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Generally, long-term dispatchable purchased power contracts require a periodic capacity payment and a charge for the delivered associated energy. Some long-term purchased power contracts only contain a charge for the purchased energy. NSP-Minnesota also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

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

NSP System Resource Plans — In January 2017, the MPUC approved NSP-Minnesota's IRP that includes:

- Retirement of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026. The resulting need for 750 MW of capacity in 2026 will be addressed in a future CON proceeding;
- Acquisition of at least 1,000 MW of wind by 2019. The mix of purchased power and owned facilities was not specified;
- Acquisition of 650 MW of solar by 2021 either through the community solar gardens program or other cost-effective resources. The mix of purchased power and owned facilities was not specified;
- Acquisition of at least 400 MW of additional demand response by 2023, and a study of the technical and economic achievability of 1,000 MW of additional demand response in total by 2025; and
- Achievement of at least 444 GWh of energy efficiency in all planning years.

Minnesota Legislation — In February 2017, the Minnesota governor signed a bill into law allowing NSP-Minnesota to build a natural gas combined-cycle power plant at NSP-Minnesota's Sherco site. The plant was originally proposed as part of NSP-Minnesota's resource plan, which enables the retirement of two coal units at the Sherco site. The plant's in-service date is anticipated for 2026. Cost recovery of the plant will be subject to MPUC approval.

Wind Development — In July 2017, the MPUC approved NSP-Minnesota's proposal to add 1,550 MW of new wind generation including ownership of 1,150 MW of wind generation by NSP-Minnesota, which will help achieve NSP-Minnesota's wind acquisition goal outlined in the IRP. In March 2017, NSP-Minnesota filed an Advanced Determination of Prudence with the NDPSC and reached a settlement with the NDPSC Staff. The timing of a NDPSC order is uncertain. These projects are expected to be completed by the end of 2020 and would qualify for 100 percent of the PTC. NSP-Minnesota's total capital investment for these wind ownership projects is expected to be approximately \$1.9 billion.

In September 2017, NSP-Minnesota filed with the MPUC seeking approval to build and own the Dakota Range project, a 300 MW wind project in South Dakota. The project is expected to be placed into service by the end of 2021 and qualify for 80 percent of the PTC. The DOC recommended the MPUC deny the petition on the basis that NSP-Minnesota did not follow the standard regulatory selection process of issuing a new RFP. However, the DOC acknowledged the Dakota Range project would benefit ratepayers and the MPUC could approve the project if it determines the public interest outweighs their concern about the regulatory selection process.

These wind projects are expected to provide significant savings to NSP-Minnesota's customers and substantial environmental benefits. Projected savings/benefits assume fuel costs and generation mix consistent with various commission approved resource plans. NSP-Minnesota will provide supplemental filings to the MPUC in March 2018, which will estimate impacts of the TCJA on the wind projects.

PPA Terminations and Amendments — In 2017, NSP-Minnesota filed requests with the MPUC and the NDPSC for several initiatives including changes to four PPAs to reduce future costs for customers. These actions include the following:

- The termination of a PPA with Benson Power LLC (Benson) for its 55 MW biomass facility in Benson, Minn., including the purchase and closure of the facility. The purchase of the Benson biomass facility requires FERC approval, which was requested in August 2017. The transaction would result in payments of \$95 million to terminate the PPA and acquire the facility, as well as additional expenditures of approximately \$26 million to temporarily operate and close the facility.
- The termination of a PPA with Laurentian Energy Authority I, LLC (Laurentian) for its 35 MW of biomass facilities in Hibbing and Virginia, Minn. The termination of the Laurentian PPA would result in approximately \$109 million of contract cancellation payments over six years.
- The remaining two requested PPA changes involve a PPA extension of the Hennepin Energy Recovery Center (HERC) 34 MW waste-to-energy facility at a price reflective of current market conditions and termination of the Pine Bend 12 MW waste-to-energy PPA.

In November 2017, the MPUC approved NSP-Minnesota's request to terminate the Pine Bend PPA but rejected its request to extend the HERC PPA.

In January 2018, the MPUC issued an order approving NSP-Minnesota's petition to terminate the PPAs with Benson and Laurentian, as well as purchase and close the Benson biomass facility. All approved costs are expected to be recoverable through the FCA, including a return on NSP-Minnesota's total investment in the Benson transaction through 2028. NSP-Minnesota also reached a settlement agreement with the NDPSC Staff which allows for the termination of the PPAs with Benson, Laurentian and Pine Bend, as well as the purchase and closure of the Benson biomass facility. The NDPSC is expected to issue an order on the settlement in the second quarter of 2018. NSP-Minnesota and NSP-Wisconsin will jointly request FERC approval to modify the Interchange Agreement to share a portion of the termination costs with NSP-Wisconsin.

These terminations and amendments are intended to provide in excess of \$600 million in net cost savings to NSP System customers over the next 10 years.

Jurisdictional Cost Recovery Allocation — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC. The filing proposed a framework to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another with respect to future generation resource selection while also identifying a path for cost sharing of current resources. NSP-Minnesota's filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns the costs and benefits of each resource to the jurisdiction that supports it. In October 2017, NDPSC staff filed testimony recommending no change to the current system of proxy pricing and policy-based disallowances claiming there is a likelihood of overall increased costs and potential loss of resource diversity. Hearings are planned for the second quarter of 2018.

Minnesota State Right-Of-First Refusal (ROFR) Statute Complaint — In September 2017, LSP Transmission Holdings, LLC filed a complaint in the U.S. District Court for the District of Minnesota (Minnesota District Court) against the Minnesota Attorney General, the MPUC and the DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from near Mankato, Minn. to Winnebago, Minn. The line was estimated by MISO to cost \$103 million. The project was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenges the constitutionality of the state ROFR statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss. Oral arguments were heard in February 2018, and the matter is now pending before the Minnesota District Court. The timing and outcome of the litigation is uncertain.

Nuclear Power Operations and Waste Disposal

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

NSP-Minnesota participates with regulators and in industry groups including the NRC, the Institute of Nuclear Power Operations and Utilities Service Alliance to stay informed of advancements in nuclear safety, mitigation strategies, performance and operational effectiveness. NSP-Minnesota applies this acquired knowledge by investing in technology and services that improve nuclear operations and detect, mitigate and protect NPS-Minnesota's nuclear facilities.

NRC Regulation — The NRC regulates nuclear operations. Decisions by the NRC can significantly impact the operations of the nuclear generating plants. The costs of complying with NRC orders and requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs in customer rates, and expects future compliance costs will continue to be recoverable from customers. Estimates of the future nuclear capital expenditures related to costs of NRC compliance are included in Xcel Energy's capital forecast for electric generation. See Item 7 for further discussion of capital requirements.

Nuclear Regulatory Performance — The NRC has a Reactor Oversight Process that classifies U.S. nuclear reactors into various categories (referred to as Columns, from 1 to 5). Issues are evaluated as either green, white, yellow, or red based on their safety significance, with green representing the least safety concern and red representing the most concern.

As of Dec. 31, 2017, Monticello and PI Units 1 and 2 were in Column 1 (licensee response) with all green performance indicators and no greater than green findings or violations. Plants in Column 1 are subject to only a pre-defined set of basic NRC inspections.

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

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

Review of PI Costs — As part of NSP-Minnesota's 2016 multi-year electric rate case and IRP the MPUC ordered an investigation into NSP-Minnesota's PI nuclear investments. The issue was resolved for the 2016 multi-year electric rate case settlement; however the DOC is continuing to investigate costs of operation and performance at PI in anticipation of NSP-Minnesota's 2019 resource plan.

Nuclear Spent Fuel Storage

NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. As of Dec. 31, 2017, there were 40 casks loaded and stored at the PI plant and 16 canisters loaded and stored at the Monticello plant. An additional 24 casks for PI and 14 canisters for Monticello have been authorized by the State of Minnesota. This currently 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 begin operation of a consolidated interim storage installation.

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

In 2016, the NRC issued an order approving a settlement in which NSP-Minnesota agreed to a timeline for attaining compliance on all six canisters, as well as additional training and communications. During 2016, the NRC approved an exemption request for the completion of canister #16. That canister is now considered in compliance, and was placed in the ISFSI during 2016. In 2017, NSP-Minnesota submitted a plan and request to the NRC to restore Monticello canisters #11-15 to compliance through an exemption request. NSP-Minnesota requested that the NRC grant the exemption by October 2018.

Costs attributable to Monticello canisters #11-15 achieving full regulatory compliance within five years are currently being evaluated. No public safety issues have been raised, or are believed to exist, in this matter.

See Note 14 to the consolidated financial statements for further discussion regarding nuclear related items.

	Year Ended Dec. 31					
	2017		2016		2015	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
NSP System						
Nuclear	14,167	30%	14,191	30%	12,425	27%
Coal	14,737	30	13,681	28	15,961	35
Wind ^(a)	8,893	18	7,897	16	6,235	14
Natural Gas	5,786	12	7,810	16	6,689	15
Hydroelectric	3,080	6	3,203	7	3,326	7
Other ^(b)	2,052	4	1,480	3	1,083	2
Total	48,715	100%	48,262	100%	45,719	100%
Owned generation	36,640	75%	36,381	75%	33,818	74%
Purchased generation	12,075	25	11,881	25	11,901	26
Total	48,715	100%	48,262	100%	45,719	100%

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

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards[®] program is not included, and was approximately 17, 21 and eight million net KWh for 2017, 2016, and 2015, respectively.

Fuel Supply and Costs

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

NSP System Generating Plants	Coal ^(a)		Nuclear		Natural Gas		Weighted Average Owned Fuel Cost
	Cost	Percent	Cost	Percent	Cost	Percent	
2017	\$ 2.08	45%	\$ 0.78	45%	\$ 4.10	10%	\$ 1.72
2016	2.03	42	0.80	44	3.30	14	1.67
2015	2.15	47	0.83	40	3.89	13	1.85

(a) Includes refuse-derived fuel and wood.

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

Fuel Sources

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

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2021 and approximately 57 percent of the requirements for 2022 through 2033;
- Current contracts for conversion services cover 100 percent of the requirements through 2021 and approximately 50 percent of the requirements for 2022 through 2033; and
- Current enrichment service contracts cover 100 percent of the requirements through 2025 and approximately 29 percent of the requirements for 2026 through 2033.

Fabrication services for Monticello and PI are 100 percent committed through 2030 and 2019, respectively.

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

Coal — The NSP System normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2017 and 2016 were approximately 53 and 55 days of usage, respectively. Milder weather, purchase commitments and relatively low power and natural gas prices resulted in coal inventories being above optimal levels. NSP-Minnesota’s generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and Montana. Coal requirements for the NSP System’s major coal-fired generating plants were approximately 8.0 million tons for 2017 and 7.5 million tons for 2016. Coal requirements for 2017 increased primarily due to slightly higher natural gas prices during the year. The estimated coal requirements for 2018 are approximately 8.3 million tons.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 79 percent of their estimated coal requirements in 2018 and a declining percentage of the requirements in subsequent years. The NSP System’s general coal purchasing objective is to contract for approximately 75 percent of requirements for the first year, 40 percent of requirements in year two and 20 percent of requirements in year three. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have coal transportation contracts that provide for delivery of 100 and 25 percent of their coal requirements in 2018 and 2019, respectively. Coal delivery may be subject to interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Natural gas — The NSP System uses both firm and interruptible natural gas supply in combustion turbines and certain boilers. Natural gas supplies, transportation and storage services for power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2017 and 2016, the NSP System did not have any commitments related to gas supply contracts; however commitments related to gas transportation and storage contracts were approximately \$398 million and \$382 million, respectively. Commitments related to gas transportation and storage contracts expire in various years from 2018 to 2037.

The NSP System also has limited on-site fuel oil storage facilities and primarily relies on the spot market for incremental supplies.

Renewable Energy Sources

The NSP System’s renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. As of Dec. 31, 2017, the NSP System was in compliance with mandated RPS, which require generation from renewable resources of 25.0 percent and 12.9 percent of NSP-Minnesota and NSP-Wisconsin electric retail sales, respectively.

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

	2017	2016
Renewable	28.8%	26.1%
Wind	18.3	16.4
Hydroelectric	6.3	6.6
Biomass and solar	4.2	3.1

The NSP System also offers customer-focused renewable energy initiatives. Windsource allows customers in Minnesota, Wisconsin and Michigan to purchase electricity from renewable sources. The number of customers utilizing Windsource increased to approximately 60,900 in 2017 from 54,000 in 2016.

Additionally, to encourage the growth of solar energy in Minnesota, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards® and Made in Minnesota solar incentive programs. Over 2,800 PV systems with approximately 33.75 MW of aggregate capacity have been installed in Minnesota as of Dec. 31, 2017 and 2,000 PV systems with approximately 25.2 MW of aggregate capacity were installed as of Dec. 31, 2016. The Solar*Rewards® Community® program is another option made available to encourage use of solar energy in Minnesota. This program allows for offsite development of solar and bill credits to customers based on an approved tariffed rate.

Wind — The NSP System acquires the majority of its wind energy from PPAs. Currently, the NSP System has more than 130 of these agreements in place, with facilities ranging in size from under one MW to more than 200 MW. The NSP System owns and operates five wind farms which have the capacity to generate 852 MW.

- The NSP System had approximately 2,600 MW of wind energy on its system at the end of 2017 and 2016. In addition to receiving purchased wind energy under these agreements, the NSP System typically receives wind RECs, which are used to meet state renewable resource requirements.
- The average cost per MWh of wind energy under existing contracts was approximately \$44 for 2017 and \$43 for 2016. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements and the year of contract execution. Generally, contracts executed in 2017 continued to benefit from improvements in technology, excess capacity among manufacturers and motivation to commence new construction prior to the anticipated expiration of the federal PTCs. In December 2015, the federal PTCs were extended through 2019 with a phase down on sites that began construction in 2017.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and PPAs. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide approximately 263 MW of capacity. For 2017, PPAs provided approximately 34 MW of hydroelectric capacity. Additionally, the NSP System purchases approximately 850 MW of generation from Manitoba Hydro, which is sourced primarily from its fleet of hydroelectric facilities.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. NSP-Minnesota also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates. See Item 7 for further discussion.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. NSP-Wisconsin is a transmission owning member of the MISO RTO and operates within the MISO RTO and wholesale energy market. NSP-Wisconsin and NSP-Minnesota are jointly authorized by the FERC to make wholesale electric sales at market-based prices.

The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January. In recent years, NSP-Wisconsin has been submitting rate filings each year.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW for approval. Once the PSCW approves the fuel cost plan, utilities defer the amount of any fuel cost under-recovery or over-recovery in excess of a two percent annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. Fuel cost under-collections that exceed the two percent annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.

NSP-Wisconsin's electric fuel costs for 2017 were lower than authorized in rates and outside the two percent annual tolerance band, primarily due to lower purchased power costs coupled with moderate weather and generation sales into the MISO market. Under the fuel cost recovery rules, NSP-Wisconsin may retain approximately \$4 million of fuel costs and defer approximately \$10 million through Dec. 31, 2017. NSP-Wisconsin will file a reconciliation of 2017 fuel costs with the PSCW. The amount of any potential refund is subject to review and approval by the PSCW, which is not expected until mid-2018.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-recoveries are refunded and any under-recoveries are collected from the customers over the subsequent 12-month period.

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

Capacity and Demand

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Capacity and Demand.

Energy Sources and Related Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Energy Sources and Related Transmission Initiatives.

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse to Madison, Wis. Transmission Line — In 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a CPCN for a 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. NSP-Wisconsin's half of the line will be shared with three co-owners, Dairyland Power Cooperative, WPPI Energy and Southern Minnesota Municipal Power Agency-Wisconsin.

In 2015, the PSCW issued its order approving a CPCN and route for the project. Two groups have appealed the CPCN order to the La Crosse County Circuit Court (Circuit Court). In May 2017, the Circuit Court determined that the project was necessary, allowing construction to continue on a seven mile segment near La Crosse, Wis. The parties have appealed various aspects of the case to the Wisconsin Court of Appeals which is currently pending. The CPCN remains in full effect unless one of the parties seeks and receives a stay from the court and posts a bond to cover damages the utilities may incur due to delay. The 180-mile project is expected to cost approximately \$541 million. NSP-Wisconsin's portion of the investment, which includes AFUDC, is estimated to be approximately \$200 million. Construction on the line began in January 2016, with completion anticipated by late 2018.

Fuel Supply and Costs

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Fuel Supply and Costs.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin operates an integrated system with NSP-Minnesota. NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates. See NSP-Minnesota Wholesale and Commodity Marketing Operations.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC for its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. PSCo is not presently a member of an RTO and does not operate within an RTO energy market. PSCo is authorized by the FERC to make wholesale electric sales at market-based prices to customers outside PSCo's balancing authority area.

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

- *ECA* — Recovers fuel and purchased energy costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
- *PCCA* — Recovers purchased capacity payments.
- *SCA* — Recovers the difference between PSCo’s actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised on a quarterly basis.
- *DSMCA* — Recovers DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
- *RESA* — Recovers the incremental costs of compliance with the RES with a maximum of two percent of the customer’s bill.
- *WCA* — Premium service for customers who choose to pay for renewable resources.
- *TCA* — Recovers costs associated with transmission investment outside of rate cases.
- *CACJA* — Recovers costs associated with the CACJA.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. PSCo’s wholesale customers pay the full cost of certain renewable energy purchase and generation costs through a fuel clause and in exchange receive RECs associated with those resources. The wholesale customers pay their jurisdictional allocation of production costs through a fully forecasted formula rate with true-up.

Capacity and Demand

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

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

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

Energy Sources and Related Transmission Initiatives

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

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

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

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

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

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

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

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

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

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

Approval of the CEP portfolio could increase capital investment up to \$1.5 billion, based on a preliminary estimate. The level of capital investment may decline due to lower renewable pricing and the ultimate composition of assets selected as part of the RFP process. The expected cost and potential capital investment of the CEP will be determined once a recommended portfolio is filed with the CPUC. The CEP portfolio is not included in PSCo and Xcel Energy's base capital expenditures forecast. See Item 7. Management's Discussion and Analysis of Financial Condition and Result of Operations - Liquidity and Capital Resources for further discussion of the capital forecast.

Boulder, Colorado Municipalization — In 2011, in the City of Boulder, Colorado (Boulder), voters passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Since that time, there have been various legal proceedings in multiple venues with jurisdiction over Boulder's plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility as premature and the Colorado Court of Appeals ruled in PSCo's favor, vacating a lower court decision. Subsequently, the Colorado Supreme Court granted Boulder's petition to review the Court of Appeals decision and oral arguments were held on Feb. 14, 2018. A ruling on the petition is anticipated in 2018.

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

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

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

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

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

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

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

Energy Source Statistics

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

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

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

Fuel Supply and Costs

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

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

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

Fuel Sources

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

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

Natural gas — PSCo uses both firm and interruptible natural gas supply in combustion turbines and certain boilers. Natural gas supplies for PSCo’s power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, any remaining forecasted requirements are able to be procured through a liquid spot market. The majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company and the balance of natural gas supply contracts have variable pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 11 to the consolidated financial statements for further discussion.

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

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

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

Renewable Energy Sources

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

Renewable energy as a percentage of PSCo’ total energy:

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

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

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

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

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

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to hedging and sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved joint operating agreement. See Item 7 for further discussion.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS’ retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS’ rates in those communities. The municipalities’ rate setting decisions are subject to review by the PUCT, which has ultimate authority to set the rates SPS charges in the municipalities. The NMPRC also has jurisdiction over the issuance of securities. SPS is regulated by the FERC for its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. As approved by the FERC, SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

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

- *DCRF* — Recovers distribution costs in Texas that are not included in base rates.
- *EECRF* — Recovers costs associated with providing energy efficiency programs in Texas.
- *EE rider* — Recovers costs associated with providing energy efficiency programs in New Mexico.
- *FPPCAC* — Adjusts monthly to recover the actual fuel and purchased power costs.
- *PCRF* — Allows recovery of certain purchased power costs in Texas that are not included in base rates.
- *RPS* — Recovers deferred costs associated with renewable energy programs in New Mexico.
- *TCRF* — Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges in Texas that are not included in base rates.

Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS’ retail electric tariff. SO₂ and NO_x allowance revenues and costs are also recovered through the fixed fuel and purchased energy recovery factor. The regulations allow retail fuel factors to change up to three times per year.

The fixed fuel and purchased energy recovery factor provides for the over- or under-recovery of fuel and purchased energy expenses. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed four percent of the utility’s annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

PUCT regulations require periodic examination of SPS’ fuel and purchased energy costs, the efficient use of fuel and purchased energy, fuel acquisition and management policies and purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review fuel and purchased energy costs at least every three years. In June 2016, SPS filed its fuel reconciliation application which reconciled fuel and purchased power costs for 2013 through 2015. In March 2017, the PUCT approved the application.

SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased economic energy cost adjustment clause accepted for filing by the FERC.

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2018, assuming normal weather conditions, is as follows:

	System Peak Demand (in MW)			
	2017	2016	2015	2018 Forecast
SPS	4,374	4,836	4,678	4,483

The peak demand for the SPS system typically occurs in the summer. The 2017 system peak demand for SPS occurred on July 26, 2017. The decline in peak load from 2016 to 2017 is in part due to cooler weather in 2017. Additionally, the partial requirement contract with Golden Spread ended May 2017, contributing to the lower actual peak demand for SPS. The 2018 forecast assumes normal peak day weather.

Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements. In addition, SPS has evaluated water supply issues at its Tolk facility, concluding that additional resource investment will be required to operate the plant through its existing life. The Ogallala aquifer in this region of the country has depleted more rapidly than expected and SPS installed a horizontal water well that could help to delay the need for a more substantial investment solution. As a result of this issue and to a lesser extent, future environmental rules facing the plant, SPS is seeking a decrease to the remaining life of the facility in its current Texas and New Mexico rate case proceedings (see Note 12).

Purchased Power — SPS has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts typically require a periodic capacity charge and an energy charge for energy actually purchased. SPS also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations or to obtain energy at a lower cost.

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

TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV Transmission Line — In 2014, SPP evaluated anticipated transmission needs for certain parts of the SPP region which is commonly known as the High Priority Incremental Load Study. As a result, SPS received 44 transmission projects, with an original estimated cost of \$557 million. The most significant of these projects are the TUCO Substation to the Yoakum County Substation to the Hobbs Plant Substation and the Hobbs Plant Substation to the China Draw Substation transmission line projects.

In 2016 and 2017, SPS received CCNs for the three segments of the TUCO Substation to Yoakum County Substation to Hobbs Plant Substation 345 KV transmission line, which are expected to be in service in the second quarter of 2020. This 345 KV transmission line is part of a larger project which includes an additional 345 KV transmission line from the Hobbs Plant Substation to the China Draw Substation, which was approved by the NMPRC in 2016 and is anticipated to be in service by June 2018. The estimated total investment for these transmission lines is approximately \$402 million.

Wind Proposals — In March 2017, SPS filed proposals with the NMPRC and the PUCT to build, own and operate 1,000 MW of new wind generation through two wind farms for a cost of approximately \$1.6 billion. In addition, the proposal includes a PPA for 230 MW of wind.

In December 2017, SPS and parties filed a unanimous stipulation with the NMPRC. The stipulation is subject to approval by the NMPRC. The key terms of the stipulation are listed below:

- An investment cap of \$1,675 per KW, which is equal to 102.5 percent of the estimated construction costs;
- SPS customers would receive a credit to their bills if actual capacity factors fall below 48 percent;
- SPS customers would receive 100 percent of the federal PTC; and
- SPS can file a HTY rate case and include projected capital additions for the wind farms five months beyond the end of the test year. Interim rates would also be made effective 30 days after filing which will allow SPS to closely match the start of cost recovery for that wind farm with the in service date.

On Feb. 9, 2018, the Hearing Examiner issued a certification of stipulation (certification) recommending approval of all but one aspect of the stipulation, which is the provision for interim rate recovery of SPS' investment in the two wind farms. On Feb. 19, 2018, SPS filed exceptions to the recommended decision, as did other parties to the stipulation.

In addition, SPS has reached a settlement in principle with parties in Texas and is working towards finalizing a stipulation. SPS has shared an updated analysis with all parties which shows the wind projects remain cost-effective following the passage of the TCJA. The settlements require approval by the NMPRC and PUCT. Both commissions are expected to rule on the settlements by the end of the first quarter of 2018. The Hale wind project in Texas and the Sagamore wind project in New Mexico are scheduled to be in service by mid-2019 and year-end 2020, respectively.

Lubbock Power & Light's (LP&L's) Request for Participation in ERCOT — In September 2017, LP&L filed its application with the PUCT and proposed to transition a portion of its load to ERCOT no later than June 2021. As a result of LP&L's proposal, approximately \$18 million in wholesale transmission revenue would be reallocated to remaining SPS transmission customers at the time of the load transition. In November 2017, SPS and various other parties, including the PUCT Staff, filed direct testimony in response to LP&L's application. SPS proposed an Interconnection Switching Fee to be determined by the PUCT.

In February 2018, SPS, LP&L, the PUCT Staff and various other parties filed a stipulation that provides SPS' customers with an Interconnection Switching Fee of approximately \$24 million to compensate them for the transfer of LP&L's load from SPP to ERCOT. Under the settlement, SPS would allocate the Interconnection Switching Fee to its Texas and New Mexico retail and wholesale transmission customers through a bill credit following LP&L's load transition to ERCOT (tentatively, June 2021). A PUCT decision is expected in March 2018. No final decision regarding LP&L's departure or its potential timing is expected until completion of the PUCT proceedings.

Texas State ROFR Request for Declaratory Order — In February 2017, SPS and SPP filed a joint petition with the PUCT for a declaratory order regarding SPS' ROFR. SPS contended that Texas law grants an incumbent electric utility, operating in areas outside of ERCOT, the ROFR to construct new transmission facilities located in the utility's service area. SPP stated that Texas law does not provide a clear statement regarding the ROFR for incumbent utilities and therefore SPP was abiding by the portion of its OATT, which requires competitive solicitation to construct and operate new transmission facilities within areas of Texas' SPP footprint.

In October 2017, the PUCT issued an order finding that SPS does not possess an exclusive right to construct and operate transmission facilities within its service area. In January 2018, SPS and two other parties filed appeals of the PUCT's order in the Texas State District Court. The appeals have been consolidated. A schedule has not been set for the case.

Energy Source Statistics

	Year Ended Dec. 31					
	2017		2016		2015	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
SPS						
Coal	10,999	40%	10,990	39%	12,441	44%
Natural Gas	9,950	36	10,909	38	10,514	36
Wind ^(a)	5,828	21	6,120	22	5,252	19
Other ^(b)	770	3	347	1	150	1
Total	27,547	100%	28,366	100%	28,357	100%
Owned generation	12,845	47%	15,015	53%	16,480	58%
Purchased generation	14,702	53	13,351	47	11,877	42
Total	27,547	100%	28,366	100%	28,357	100%

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

(b) Distributed generation from the Solar*Rewards program is not included, was approximately 26, 14 and 13 million net KWh for 2017, 2016, and 2015, respectively.

Fuel Supply and Costs

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

SPS Generating Plants	Coal		Natural Gas		Weighted Average Owned Fuel Cost
	Cost	Percent	Cost	Percent	
2017	\$ 2.18	74%	\$ 3.39	26%	\$ 2.50
2016	2.12	70	2.81	30	2.32
2015	2.12	73	3.11	27	2.39

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

Fuel Sources

Coal — SPS purchases all of the coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO. 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. The coal supply contract with TUCO expires on Dec. 31, 2022 for both Harrington and Tolk.

SPS normally maintains approximately 35 - 50 days of coal inventory. As of Dec. 31, 2017 and 2016, coal inventories at SPS were approximately 52 and 64 day supply, respectively. Milder weather, purchase commitments and relatively low power and natural gas prices resulted in coal inventories being above optimal levels. SPS' generation stations primarily use low-sulfur western coal from mines operating in Wyoming. TUCO has coal agreements to supply 79 percent of SPS' estimated coal requirements in 2018 and a declining percentage of requirements in subsequent years. SPS' general coal purchasing objective is to contract for approximately 75 percent of requirements for the first year, 40 percent of requirements in year two and 20 percent of requirements in year three.

Natural gas — SPS uses both firm and interruptible natural gas supply in combustion turbines and certain boilers. Natural gas for SPS' power plants is procured under contracts to provide an adequate supply of fuel, which typically is purchased with terms of one year or less. The transportation and storage contracts expire between 2018 to 2033. All of the natural gas supply contracts have variable pricing that is tied to various natural gas indices.

Most transportation contract pricing is based on FERC and Railroad Commission of Texas approved transportation tariff rates. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. SPS' commitments related to gas supply contracts were approximately \$11 million and \$17 million and commitments related to gas transportation and storage contracts were approximately \$191 million and \$161 million at Dec. 31, 2017 and 2016, respectively.

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

Renewable Energy Sources

SPS' renewable energy portfolio includes wind and solar power from PPAs. As of Dec. 31, 2017, SPS is in compliance with mandated RPS, which require generation from renewable resources of 3.7 percent of Texas electric retail sales and 15.0 percent of New Mexico electric retail sales.

Renewable energy as a percentage of SPS' total energy:

	2017	2016
Renewable.....	24.0%	22.8%
Wind.....	21.2	21.6
Solar.....	1.8	1.2

SPS also offers customer-focused renewable energy initiatives. Windsource[®] allows customers in New Mexico to purchase electricity from renewable sources. The number of customers utilizing Windsource increased to approximately 940 in 2017 from 900 in 2016.

Wind — SPS acquires its wind energy from IPP contracts and QF tariffs. SPS currently has 24 of these agreements in place, with facilities ranging in size from under two MW to 250 MW.

- SPS had approximately 1,500 MW of wind energy on its system at the end of 2017 and 2016. In addition to receiving purchased wind energy under these agreements, SPS typically receives wind RECs on certain agreements which are used to meet state renewable resource requirements.
- The average cost per MWh of wind energy under the IPP contracts and QF tariffs was approximately \$27 for 2017 and \$25 for 2016. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state-specific renewable resource requirements and the year of contract execution. Generally, contracts executed in 2017 continued to benefit from improvements in technology, excess capacity among manufacturers, and motivation to commence new construction prior to the anticipated expiration of the federal PTCs. In December 2015, the federal PTCs were extended through 2019 with a phase down on sites that began construction in 2017.

Wholesale and Commodity Marketing Operations

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 hedge sales and purchases. See Item 7 for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, asset transactions and mergers, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries and TransCos, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 12 to the accompanying consolidated financial statements for a discussion of other regulatory matters.

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

FERC Order, ROE Policy — In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including two ROE complaints involving the MISO TOs, which include NSP-Minnesota and NSP-Wisconsin. In April 2017, the District of Columbia Circuit (D.C. Circuit) vacated and remanded the June 2014 ROE order. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for the NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. The FERC has yet to act on the D.C. Circuit's decision. See Note 12 to the consolidated financial statements for discussion of the D.C. Circuit's decision and the impact on the MISO ROE Complaints.

DOE Grid Resiliency Notice of Proposed Rule (NOPR) — In September 2017, the DOE requested the FERC to consider and adopt a Grid Resiliency and Pricing Rule to address threats to the U.S. electrical grid. Under the proposed rule, coal and nuclear generation facilities would have to meet certain criteria to qualify for full recovery of their costs including a fair rate of return. In January 2018, the FERC rejected the DOE's proposal, but alternatively initiated an inquiry into how RTOs and Independent System Operators address grid resilience. Efforts to resolve U.S. grid resilience issues may result from this proceeding and Xcel Energy plans to monitor and respond as necessary.

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

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

Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2017	2016	2015
Electric sales (Millions of KWh)			
Residential	24,216	24,726	24,498
Large C&I	27,951	27,664	27,719
Small C&I	35,493	35,830	35,806
Public authorities and other	1,055	1,103	1,071
Total retail	<u>88,715</u>	<u>89,323</u>	<u>89,094</u>
Sales for resale	18,349	18,694	15,283
Total energy sold	<u><u>107,064</u></u>	<u><u>108,017</u></u>	<u><u>104,377</u></u>
Number of customers at end of period			
Residential	3,082,974	3,053,732	3,023,494
Large C&I	1,241	1,228	1,229
Small C&I	433,883	432,012	429,617
Public authorities and other	69,376	68,935	68,595
Total retail	<u>3,587,474</u>	<u>3,555,907</u>	<u>3,522,935</u>
Wholesale	58	52	47
Total customers	<u><u>3,587,532</u></u>	<u><u>3,555,959</u></u>	<u><u>3,522,982</u></u>
Electric revenues (Millions of Dollars)			
Residential	\$ 2,975	\$ 2,966	\$ 2,891
Large C&I	1,779	1,707	1,690
Small C&I	3,463	3,328	3,304
Public authorities and other	143	140	137
Total retail	<u>8,360</u>	<u>8,141</u>	<u>8,022</u>
Wholesale	719	693	660
Other electric revenues	597	666	594
Total electric revenues	<u><u>\$ 9,676</u></u>	<u><u>\$ 9,500</u></u>	<u><u>\$ 9,276</u></u>
KWh sales per retail customer	24,729	25,120	25,290
Revenue per retail customer	\$ 2,330	\$ 2,289	\$ 2,277
Residential revenue per KWh	12.29¢	11.99¢	11.80¢
Large C&I revenue per KWh	6.36	6.17	6.10
Small C&I revenue per KWh	9.76	9.29	9.23
Total retail revenue per KWh	9.42	9.11	9.00
Wholesale revenue per KWh	3.92	3.71	4.32

	Year Ended Dec. 31					
	2017		2016		2015	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Xcel Energy						
Coal	40,344	36%	40,566	36%	47,003	43%
Natural Gas	24,932	23	27,351	25	25,151	23
Wind ^(a)	22,526	21	22,123	20	18,186	17
Nuclear	14,168	13	14,191	13	12,895	12
Hydroelectric	3,866	4	4,435	4	4,001	4
Other ^(b)	3,329	3	2,167	2	1,456	1
Total	109,165	100%	110,833	100%	108,692	100%
Owned generation	72,539	66%	74,149	67%	73,279	67%
Purchased generation	36,626	34	36,684	33	35,413	33
Total	109,165	100%	110,833	100%	108,692	100%

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

(b) Includes energy from other sources, including solar, biomass, oil and refuse. Distributed generation from the Solar*Rewards program is not included, and was approximately 435, 430 and 266 million net KWh for 2017, 2016 and 2015, respectively.

NATURAL GAS UTILITY OPERATIONS

Overview

Xcel Energy operates natural gas local distribution companies in six states, including Minnesota, Wisconsin, Michigan, South Dakota, North Dakota, and Colorado with PSCo being the largest. The most significant developments in the natural gas operations of the utility subsidiaries are uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential and small C&I customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2017, average annual sales to the typical residential customer declined 17 percent, while sales to the typical small C&I customer declined 10 percent, each on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost-recovery mechanisms, high prices can encourage further efficiency efforts by customers.

The PHMSA

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

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

Xcel Energy has been taking actions that were intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective. PSCo and NSP-Minnesota can generally recover costs to comply with the transmission and distribution integrity management programs through the PSIA and GUIC riders, respectively.

Public Utility Regulation

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

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

NSP-Minnesota also recovers costs associated with transmission and distribution pipeline integrity management programs through its GUIC rider. Costs recoverable under the GUIC rider include funding for pipeline assessments as well as deferred costs from NSP-Minnesota’s existing sewer separation and pipeline integrity management programs. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

Minnesota state law requires utilities to invest 0.5 percent of their state natural gas revenues in CIP. These costs are recovered through customer base rates and an annual cost-recovery mechanism for the CIP expenditures.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 893,062 MMBtu, which occurred on Dec. 26, 2017 and 800,232 MMBtu, which occurred on Jan. 18, 2016.

NSP-Minnesota purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 640,489 MMBtu per day. In addition, NSP-Minnesota contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 29 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 30 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. In February 2017, the MPUC approved NSP-Minnesota’s contract demand levels for the 2016 through 2017 heating season. Demand levels for the 2017 through 2018 heating season were filed with the MPUC in August 2017.

Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota’s regulated retail natural gas distribution business:

2017	\$	3.89
2016		3.47
2015		4.07

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

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2018 through 2033.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2017, NSP-Minnesota was committed to approximately \$439 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 27 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

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

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and the MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, the PSCW and the MPSC for pipeline safety compliance.

Natural Gas Cost-Recovery Mechanisms — NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin operations to recover the actual cost of natural gas and transportation and storage services. The PSCW has the authority to disallow certain costs if it finds NSP-Wisconsin was not prudent in its procurement activities.

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

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Wisconsin was 160,170 MMBtu, which occurred on Dec. 26, 2017 and 155,583 MMBtu, which occurred on Jan. 18, 2016.

NSP-Wisconsin purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 139,293 MMBtu per day. In addition, NSP-Wisconsin contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 33 percent of winter natural gas requirements and 34 percent of peak day firm requirements of NSP-Wisconsin.

NSP-Wisconsin also owns and operates one LNG plant with a storage capacity of 270,000 Mcf equivalent to help meet its peak requirements. This peak-shaving facility has a production capacity equivalent to 18,000 MMBtu of natural gas per day, or approximately 12 percent of peak day firm requirements. LNG plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Wisconsin is required to file a natural gas supply plan with the PSCW annually to change natural gas supply contract levels to meet peak demand. NSP-Wisconsin's winter 2017-2018 supply plan was approved by the PSCW in October 2017.

Natural Gas Supply and Costs

NSP-Wisconsin actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk and economical rates. In addition, NSP-Wisconsin conducts natural gas price hedging activity that has been approved by the PSCW.

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

2017	\$	3.88
2016		3.62
2015		4.11

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

The cost of natural gas supply, transportation service and storage service is recovered through various cost-recovery adjustment mechanisms. NSP-Wisconsin has firm natural gas transportation contracts with several pipelines, which expire in various years from 2018 through 2029.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2017, NSP-Wisconsin was committed to approximately \$84 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing long-term and short-term agreements from approximately 10 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

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

PSCo

Public Utility Regulation

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

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

- *GCA* — Recovers the actual costs of purchased natural gas and transportation to meet the requirements of its customers and is revised quarterly to allow for changes in natural gas rates.
- *DSMCA* — Recovers costs of DSM and performance initiatives to achieve various energy savings goals.
- *PSIA* — Recovers costs associated with transmission and distribution pipeline integrity management programs and two projects to replace large transmission pipelines.

Capability and Demand

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

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

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

Natural Gas Supply and Costs

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

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

2017	\$	3.45
2016		3.27
2015		3.92

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

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

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

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

SPS

Natural Gas Facilities Used for Electric Generation

SPS does not provide retail natural gas service, but purchases and transports natural gas for certain of 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 certain natural gas transactions in interstate commerce, and to the jurisdiction of the PHMSA and the PUCT for pipeline safety compliance.

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

Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2017	2016	2015
Natural gas deliveries (Thousands of MMBtu)			
Residential	134,189	132,853	135,394
C&I	87,271	84,082	86,093
Total retail	221,460	216,935	221,487
Transportation and other	142,497	133,498	125,263
Total deliveries	363,957	350,433	346,750
Number of customers at end of period			
Residential	1,856,221	1,835,507	1,814,321
C&I	157,798	157,286	156,306
Total retail	2,014,019	1,992,793	1,970,627
Transportation and other	7,705	7,316	6,981
Total customers	2,021,724	2,000,109	1,977,608
Natural gas revenues (Millions of Dollars)			
Residential	\$ 1,006	\$ 930	\$ 1,043
C&I	524	469	547
Total retail	1,530	1,399	1,590
Transportation and other	120	132	82
Total natural gas revenues	\$ 1,650	\$ 1,531	\$ 1,672
MMBtu sales per retail customer	109.96	108.86	112.39
Revenue per retail customer	\$ 760	\$ 702	\$ 807
Residential revenue per MMBtu	7.50	7.00	7.70
C&I revenue per MMBtu	6.00	5.58	6.36
Transportation and other revenue per MMBtu	0.84	0.99	0.65

GENERAL

Seasonality

The demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. See Item 7 for further discussion.

Competition

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

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

In addition, FERC Order 1000 seeks to establish competition for construction and operation of certain new electric transmission facilities. State public utilities commissions have created resource planning programs that promote competition in the acquisition of electricity generation resources used to provide service to retail customers. Xcel Energy Inc.'s utility subsidiaries also have franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means for its citizens to access electric power or gas, such as municipalization. While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, Xcel Energy believes their rates and services are competitive with currently available alternatives.

ENVIRONMENTAL MATTERS

Xcel Energy's facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy's facilities have been designed and constructed to operate in compliance with applicable environmental standards. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or what effect future laws or regulations may have upon Xcel Energy's operations. See Item 7 and Notes 12 and 13 to the consolidated financial statements for further discussion.

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

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Starting in 2011, Xcel Energy began reporting GHG emissions to the EPA under the EPA's mandatory GHG Reporting Program.

Xcel Energy estimates that in 2017, it reduced the CO₂ emissions associated with the electric generating resources used to serve its customers by 35 percent from 2005 levels. This reduction accounts for emissions both from electric generating plants owned by Xcel Energy as well as purchased power. To achieve this goal, Xcel Energy primarily relied on strategies that resulted in:

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

CAPITAL SPENDING AND FINANCING

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

EMPLOYEES

As of Dec. 31, 2017, Xcel Energy had 11,075 full-time employees and 59 part-time employees, of which 5,115 were covered under collective-bargaining agreements. See Note 9 to the consolidated financial statements for further discussion.

EXECUTIVE OFFICERS ^(a)

Name	Age ^(b)	Current and Recent Positions Held
Ben Fowke	59	Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc., August 2011 to present. Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS, January 2015 to present. Previously, President and Chief Operating Officer, Xcel Energy Inc., August 2009 to August 2011.
Christopher B. Clark . . .	51	President and Director, NSP-Minnesota, January 2015 to present. Previously, Regional Vice President, Rates and Regulatory Affairs, NSP-Minnesota, October 2012 to December 2014; Managing Director, Government and Regulatory Affairs, NSP-Minnesota, January 2012 to October 2012; Managing Attorney, Xcel Energy Inc., November 2007 to January 2012.
David L. Eves	59	President and Director, PSCo, January 2015 to present. Previously, President, Director and Chief Executive Officer, PSCo, December 2009 to December 2014. Effective March 1, 2018 he will serve as Executive Vice President and Group President, Utilities.
Robert C. Frenzel	47	Executive Vice President, Chief Financial Officer, Xcel Energy Inc., May 2016 to present. Previously, Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp., an electric utility and power generation company, February 2012 to April 2016; Senior Vice President for Corporate Development, Strategy and Mergers and Acquisitions, Energy Future Holdings Corp., February 2009 to February 2012. In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including Texas Competitive Energy Holdings (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.
David T. Hudson	57	President and Director, SPS, January 2015 to present. Previously, President, Director and Chief Executive Officer, SPS, January 2014 to December 2014; Director, Community Service & Economic Development, SPS, April 2011 to January 2014; Director, Strategic Planning, SPS, May 2008 to April 2011.
Kent T. Larson	58	Executive Vice President and Group President Operations, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Group President Operations, Xcel Energy Services Inc., August 2014 to December 2014; Senior Vice President Operations, Xcel Energy Services Inc., September 2011 to August 2014; Chief Energy Supply Officer, Xcel Energy Services Inc., March 2010 to September 2011.
Marvin E. McDaniel, Jr.	58	Executive Vice President, Group President, Utilities, and Chief Administrative Officer, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, Chief Administrative Officer, Xcel Energy Inc., August 2012 to December 2014; Senior Vice President and Chief Administrative Officer, Xcel Energy Services Inc., September 2011 to August 2012; Vice President and Chief Administrative Officer, Xcel Energy Services Inc., August 2009 to September 2011 and Vice President, Talent and Technology Business Areas, Xcel Energy Services Inc., August 2009 to September 2011. Xcel Energy has previously announced that Marvin E. McDaniel, Jr. will retire in 2018. Effective March 1, 2018 he will serve as Executive Vice President and Chief Administrative Officer.
Timothy O'Connor	58	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc., February 2013 to present. Previously, Acting Chief Nuclear Officer, NSP-Minnesota, September 2012 to February 2013; Vice President, Engineering and Nuclear Regulatory Compliance and Licensing July 2012 to September 2012; Monticello Site Vice President, May 2007 to July 2012.
Judy M. Poferl	58	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Corporate Secretary, Xcel Energy Inc., May 2013 to December 2014; President, Director and Chief Executive Officer, NSP-Minnesota, August 2009 to May 2013.
Jeffrey S. Savage	46	Senior Vice President, Controller, Xcel Energy Inc., January 2015 to present. Previously, Vice President, Controller, Xcel Energy Inc., September 2011 to December 2014; Senior Director, Financial Reporting, Corporate and Technical Accounting, Xcel Energy Services Inc., December 2009 to September 2011.
Mark E. Stoering	57	President and Director, NSP-Wisconsin, January 2015 to present. Previously, President, Director and Chief Executive Officer, NSP-Wisconsin, January 2012 to December 2014; Vice President, Portfolio Strategy and Business Development, Xcel Energy Services Inc., August 2000 to December 2011.
Scott M. Wilensky	61	Executive Vice President, General Counsel, Xcel Energy Inc., January 2015 to present. Previously, Senior Vice President, General Counsel, Xcel Energy Inc., September 2011 to December 2014; Vice President, Regulatory and Resource Planning, Xcel Energy Services Inc., September 2009 to September 2011.

^(a) No family relationships exist between any of the executive officers or directors.^(b) Ages as of Dec. 31, 2017.

Item 1A — Risk Factors

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

Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk, and our Board of Directors employs an effective process for doing so. Management and each Board of Directors' committee have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economies and the environment when identifying, assessing, managing and mitigating risk. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the financial disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. The business planning process also identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals, and determines how to prevent inappropriate risk-taking.

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

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

The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Xcel Energy. First, the Board of Directors regularly reviews management's key risk assessment and analyzes areas of existing and future risks and opportunities. In addition, the Board of Directors assigns oversight of certain critical risks to each of its four standing committees to ensure these risks are well understood and are given focused oversight by the appropriate committee. The Audit Committee is responsible for reviewing the adequacy of risk oversight and affirming that appropriate oversight occurs. New risks are considered and assigned as appropriate during the annual Board of Directors' and committee evaluation process, and committee charters and annual work plans are updated accordingly. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration where deemed appropriate to ensure broad Board of Directors' understanding of the nature of the risk. Finally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Risks Associated with Our Business

Environmental Risks

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

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

We are also subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. Failure to meet the requirements of these mandates may result in fines or penalties, which could have a material effect on our results of operations. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates or other environmental requirements, it could have a material effect on our results of operations, financial position or cash flows.

In addition, existing environmental laws or regulations may be revised, and new laws or regulations may be adopted or become applicable to us, including but not limited to, regulation of mercury, NO_x, SO₂, CO₂ and other GHGs, particulates, cooling water intakes, water discharges and ash management. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

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

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

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

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

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

Financial Risks

Our profitability depends in part on the ability of our utility subsidiaries to recover their costs from their customers and there may be changes in circumstances or in the regulatory environment that 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. The utility commissions in the states where we operate regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. The FERC has jurisdiction, among other things, over wholesale rates for electric transmission service, the sale of electric energy in interstate commerce and certain natural gas transactions in interstate commerce.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment. Our utility subsidiaries provide service at rates approved by one or more regulatory commissions. These rates are generally regulated and based on an analysis of the utility's costs incurred in a test year. Our utility subsidiaries are subject to both future and historical test years depending upon the regulatory mechanisms approved in each jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital, in a continued low interest rate environment there has been pressure pushing down ROE. There can also be no assurance that the applicable regulatory commission will judge all the costs of our utility subsidiaries to have been prudent, which could result in cost disallowances, or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Changes in the long-term cost-effectiveness or changes to the operating conditions of our assets may result in early retirements and while regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs leaving all or a portion of these asset costs stranded. Higher than expected inflation may increase costs of construction and operations. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers, or these factors could cause the operating utilities to exceed commitments made regarding cost caps and result in less than full recovery. Overall, management currently believes prudently incurred costs are generally recoverable given the existing regulatory mechanisms in place.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our 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 any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time, or that a rating will not be lowered or withdrawn entirely by a rating agency. Significant events including a major disallowance of costs, significantly lower returns on equity or equity ratios or impacts of tax policy changes, among others, may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. Any downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous issues and events throughout the world economy. Capital market disruption events and resulting broad financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

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

We are subject to credit risks.

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

Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and/or breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

We may at times have direct credit exposure in our short-term wholesale and commodity trading activity to various financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as CAISO, SPP, PJM, MISO and ERCOT, in which any credit losses are socialized to all market participants.

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

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

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions, including mortality tables, have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans with modifications that allowed additional flexibility in the timing of contributions. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving Xcel Energy could trigger settlement accounting and could require Xcel Energy to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

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

Our self-insured costs of health care benefits for eligible employees have increased in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial position and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Changes in industry standards utilized by management in key assumptions (e.g., mortality tables) could have a significant impact on future liabilities and benefit costs. Legislation related to health care could also significantly change our benefit programs and costs.

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

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness and pay dividends depends upon the operating cash flows of our subsidiaries and the payment of dividends to us. 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 to us depends on any statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets. Also, our utility subsidiaries are regulated by various state utility commissions, which possess broad powers to ensure that the needs of the utility customers are being met.

If our utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected.

Federal tax law may significantly impact our business.

Xcel Energy's utility subsidiaries collect through regulated rates its estimated federal, state and local tax payments. There are a number of provisions in federal tax law designed to incentivize capital investments which have benefited our customers by keeping our utility subsidiaries' rates lower than rates calculated without such provisions. Examples include the use of accelerated depreciation for most of our capital investments, PTCs for wind energy, ITCs for solar energy and R&E tax credits and deductions. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Changes to tax depreciable lives and the value of various tax credits could change the economics of resources and our resource selections. While regulation allows us to incorporate changes in tax law into the rate-setting process, there could be timing delays before regulated rates provide for realization of the tax changes in revenues. In addition, certain IRS tax policies such as the requirement to utilize normalization may impact our ability to economically deliver certain types of resources relative to market prices.

Operational Risks

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

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

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

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

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

Most electric utility investments are long-lived and are planned to be used for decades. Transmission and generation investments typically have long lead times, and therefore are planned well in advance of when they are brought in-service subject to long-term resource plans. These plans are based on numerous assumptions over the planning horizon such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. The electric utility sector is undergoing a period of significant change. For example, public policy has driven increases in appliance and lighting efficiency and energy efficient buildings, wider adoption and lower cost of renewable generation and distributed generation, including community solar gardens and customer-sited solar, shifts away from coal generation to decrease CO₂ emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Over time, customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources as well as stranded costs if Xcel Energy is not able to fully recover the costs and investments. These changes also introduce additional uncertainty into long-term planning which gives rise to a risk that the magnitude and timing of resource additions and growth in customer demand may not coincide, and that the preference for the types of additions may change from planning to execution. In addition, we are also subject to longer-term availability of the natural resource inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

The resource plans reviewed and approved by our state regulators assume continuation of the traditional utility cost of service model under which utility costs are recovered from customers as they receive the benefit of service. Xcel Energy is engaged in significant and ongoing infrastructure investment programs to accommodate renewable distributed generation and to maintain high system reliability. Changing customer expectations and changing technologies are requiring significant investments in advanced grid infrastructure. This also increases the exposure to potential outdated technologies and the resultant risks. Xcel Energy is also investing in renewable and natural gas-fired generation to reduce our CO₂ emissions profile. The inability of coal mining companies to attract capital could disrupt longer-term supplies. Early plant retirements that may result from these changes could expose us to premature financial obligations, which could result in less than full recovery of all remaining costs. Both decreasing use per customer driven by appliance and lighting efficiency and the availability of cost-effective distributed generation puts downward pressure on load growth. This could lead to under recovery of costs, excess resources to meet customer demand and increases in electric rates. Finally, multiple states served by a single system may not agree as to the appropriate resource mix and the differing views may lead to costs incurred to comply with one jurisdiction that are not recoverable across all of the jurisdictions served by the same assets.

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

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

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance available to cover losses that might arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. For example, similar to pensions, interest rate and other assumptions regarding decommissioning costs may change based on economic conditions and changes in the expected life of the asset may cause our funding obligations to change.

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

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

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

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

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

If we encounter market supply shortages or our suppliers are otherwise unable to meet their contractual obligations, we may be unable to fulfill our contractual obligations to our customers at previously anticipated costs. Therefore, a significant disruption could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments could have a negative impact on our cash flows and potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. The impact of these cost and reliability issues vary in magnitude for each operating subsidiary depending upon unique operating conditions such as generation fuels mix, availability of water for cooling, availability of fuel transportation including rail shipments of coal, electric generation capacity, transmission, natural gas pipeline capacity, etc. Failure to provide service due to disruptions could also result in fines, penalties or cost disallowances through the regulatory process.

Public Policy Risks

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

Increased public awareness and concern regarding climate change may result in more state, regional and/or federal requirements to reduce or mitigate the effects of GHGs. Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs on our system. International agreements could have an impact to the extent they lead to future federal or state regulations.

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

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

Some states and localities have indicated a desire to continue to pursue climate policies even in the absence of federal mandates. All of the steps that 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 standards under the CPP or the Paris Agreement, repeal of these policies would not impact those state-endorsed actions and plans. Whether under state or federal programs, an important factor is our ability to recover the costs incurred to comply with any regulatory requirements in a timely manner. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations.

Increased risks of regulatory penalties could negatively impact our business.

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

Macroeconomic Risks

Economic conditions impact our business.

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

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

Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., which may impact our ability to acquire sufficient supplies. We operate in a capital intensive industry, and federal policy on trade could significantly impact the costs of the materials we use. We may be at risk for higher than anticipated inflation both with respect to our own workforce, as well as our materials and labor that we contract for with others. There may be delays before these higher costs can be recovered in rates.

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

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any such disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition and results of operations. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. In addition, we may experience additional capital and operating costs to implement security for our plants, including our nuclear power plants under the NRC's design basis threat requirements. We have also already incurred increased costs for compliance with NERC reliability standards associated with critical infrastructure protection. In addition, we may experience additional capital and operating costs to comply with the NERC critical infrastructure protection standards as they are implemented and clarified.

The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, as well as our brand and reputation. Because our generation, the transmission systems and local natural gas distribution companies are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility or an event (such as severe storm, severe temperature extremes, wildfires, solar storms, generator or transmission facility outage, breakdown or failure of equipment, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or any disruption of work force such as may be caused by flu or other epidemic) within our operating systems or on a neighboring system. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material impact on our financial condition and results.

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

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

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

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as the information processed in our systems (such as information about our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. Our industry has begun to see an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or exposing us to liability. Our generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. Our supply chain for procurement of digital equipment may expose software or hardware to these risks and could result in a breach or significant costs of remediation. In addition, such an event would likely receive regulatory scrutiny at both the federal and state level. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. These potential cyber security incidents and corresponding regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures designed to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including the resulting disability, or failures of assets or unauthorized access to assets or information. If our technology systems were to fail or be breached, or those of our third-party service providers, we may be unable to fulfill critical business functions, including effectively maintaining certain internal controls over financial reporting. We are unable to quantify the potential impact of cyber security incidents on our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network monitoring may not be effective given the constant changes to threat vulnerability.

Rising energy prices could negatively impact our business.

Although commodity prices are currently relatively low, if fuel costs increase, customer demand could decline and bad debt expense may rise, which could have a material impact on our results of operations. While we have fuel clause recovery mechanisms 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 as compared with expenditures for fuel purchases could have an impact on our cash flows. Low fuel costs could have a positive impact on sales, though low oil and natural gas prices could negatively impact oil and gas production activities and subsequently our sales volumes and revenue. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

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

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

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

We rely on third party contractors with specific qualifications to perform work both for ongoing operations and maintenance and for capital construction. We have contractual arrangements with these contractors which typically include performance standards, progress payments, insurance requirements and security for performance. Cyber security breaches seen in the news have at times exploited third party equipment or software in order to gain access. Poor vendor performance could impact on going operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

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

Electric Utility Generating Stations:

NSP-Minnesota			Summer 2017 Net Dependable Capability (MW)
Station, Location and Unit	Fuel	Installed	
Steam:			
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511
Sherco-Becker, Minn.			
Unit 1	Coal	1976	680
Unit 2	Coal	1977	682
Unit 3	Coal	1987	517 ^(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	617
PI-Welch, Minn.			
Unit 1	Nuclear	1973	521
Unit 2	Nuclear	1974	519
Various locations, 4 Units.	Wood/Refuse-derived fuel	Various	36 ^(b)
Combustion Turbine:			
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	327
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	282
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	530
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	454
Various locations, 14 Units.	Natural Gas	Various	67
Wind:			
Border-Rolette County, N.D., 75 Units	Wind	2015	148 ^(c)
Courtenay Wind, N.D., 100 Units.	Wind	2016	195 ^(c)
Grand Meadow-Mower County, Minn., 67 Units.	Wind	2008	101 ^(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201 ^(c)
Pleasant Valley-Mower County, Minn., 100 Units	Wind	2015	196 ^(c)
		Total	7,319

^(a) Based on NSP-Minnesota's ownership of 59 percent.

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

^(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	Summer 2017 Net Dependable Capability (MW)
Steam:			
Bay Front-Ashland, Wis., 3 Units	Coal/Wood/Natural Gas	1948-1956	56
French Island-La Crosse, Wis., 2 Units	Wood/Refuse-derived fuel	1940-1948	16 ^(a)
Combustion Turbine:			
Flambeau Station-Park Falls, Wis., 1 Unit	Natural Gas	1969	— ^(b)
French Island-La Crosse, Wis., 2 Units	Oil	1974	122
Wheaton-Eau Claire, Wis., 5 Units	Natural Gas/Oil	1973	238
Hydro:			
Various locations, 63 Units	Hydro	Various	135
		Total	567

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

(b) Flambeau Station was retired on Dec. 31, 2017.

PSCo

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

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

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

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

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

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

SPS

Station, Location and Unit	Fuel	Installed	Summer 2017 Net Dependable Capability (MW)
Steam:			
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	254
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	411
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,067
Combustion Turbine:			
Carlsbad-Carlsbad, N.M., 1 Unit	Natural Gas	1968	— ^(a)
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	212
Jones-Lubbock, Texas, 2 Units	Natural Gas	2011-2013	336
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1963-1976	61
		Total	4,414

^(a) Carlsbad Unit 5 was retired on Dec. 31, 2017.

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

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	9,040	1,153	2,630	8,516
230 KV	2,157	—	12,911	9,608
161 KV	417	1,656	—	—
138 KV	—	—	92	—
115 KV	7,515	1,877	4,969	13,555
Less than 115 KV	85,458	32,600	76,988	24,795

Electric utility transmission and distribution substations at Dec. 31, 2017:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	349	203	230	454

Natural gas utility mains at Dec. 31, 2017:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	136	—	2,315	11
Distribution	11,320	2,542	22,540	—

Item 3 — Legal Proceedings

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

Additional Information

See Note 13 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1, Item 7 and Note 12 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 4 — Mine Safety Disclosures

None.

PART II

Item 5 — Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Quarterly 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 shareholders of record as of Dec. 31, 2017 was approximately 59,270. The following are the intra-day high and low stock prices based on the NYSE Composite Transactions for the quarters of 2017 and 2016 and the dividends declared per share during those quarters. See Item 7 and Note 4 to the consolidated financial statements for further discussion of Xcel Energy Inc.’s dividend policy and restrictions.

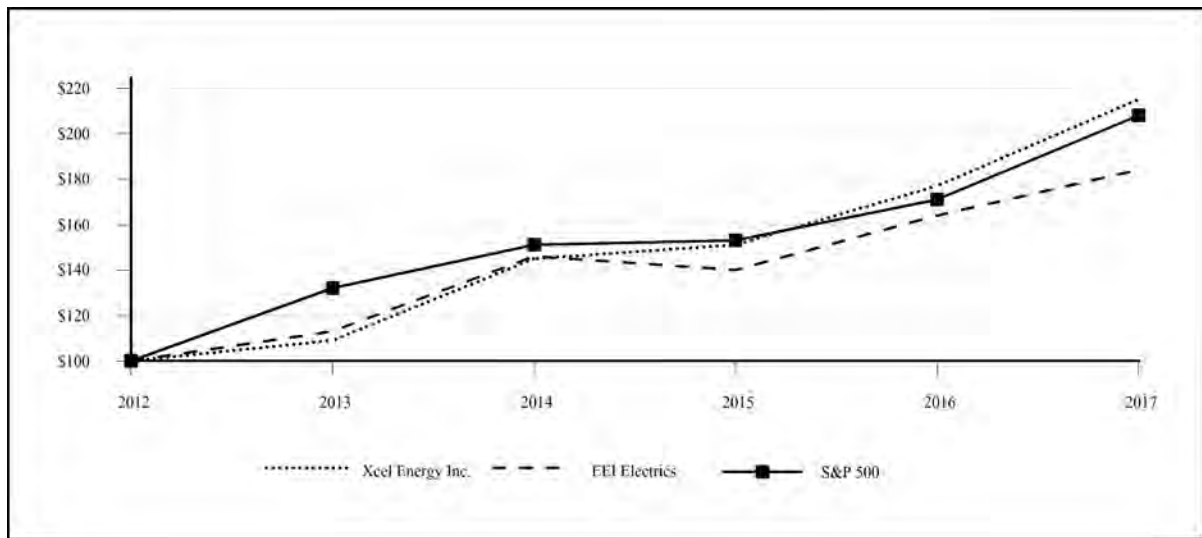
2017	High	Low	Dividends
First quarter	\$ 45.06	\$ 40.04	\$ 0.3600
Second quarter	48.50	44.00	0.3600
Third quarter	50.56	45.18	0.3600
Fourth quarter	52.22	46.86	0.3600
2016	High	Low	Dividends
First quarter	\$ 41.85	\$ 35.19	\$ 0.3400
Second quarter	44.78	38.43	0.3400
Third quarter	45.42	40.34	0.3400
Fourth quarter	41.80	38.00	0.3400

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the S&P 500 Composite Stock Price Index over the last five years (assuming a \$100 investment on Dec. 31, 2012, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 43 companies at year-end and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*

Among Xcel Energy Inc., the EEI Investor-Owned Electrics and the S&P 500



* \$100 invested on Dec. 31, 2012 in stock or index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2012	2013	2014	2015	2016	2017
Xcel Energy Inc.....	\$ 100	\$ 109	\$ 145	\$ 151	\$ 177	\$ 215
EEI Investor-Owned Electrics	100	113	146	140	164	184
S&P 500	100	132	151	153	171	208

Securities Authorized for Issuance Under Equity Compensation Plans

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

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. for the fourth quarter of fiscal year 2017, pursuant to Section 12 of the Exchange Act:

Period	Issuer Purchases of Equity Securities			
	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
Oct. 1, 2017 — Dec. 31, 2017.....	—	\$ —	—	—
Total.....	—	—	—	—

Item 6 — Selected Financial Data

Set forth below is selected financial data for Xcel Energy related to the most five recent years ended Dec. 31. This information has been derived from and should be read in conjunction with the consolidated financial statements and notes appearing elsewhere in this annual report on Form 10-K.

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2017	2016	2015	2014	2013
Operating revenues	\$ 11,404	\$ 11,107	\$ 11,024	\$ 11,686	\$ 10,915
Operating expenses	9,214	8,893	9,024	9,738	9,067
Net income	1,148	1,123	984	1,021	948
Earnings available to common shareholders	1,148	1,123	984	1,021	948
Weighted average common shares outstanding:					
Basic	509	509	508	504	496
Diluted	509	509	508	504	497
GAAP EPS:					
Basic	\$ 2.26	\$ 2.21	\$ 1.94	\$ 2.03	\$ 1.91
Diluted	2.25	2.21	1.94	2.03	1.91
Dividends declared per common share	1.44	1.36	1.28	1.20	1.11
Total assets ^{(a) (b)}	43,030	41,155	38,821	36,958	33,907
Long-term debt ^{(b) (c)}	14,520	14,195	12,399	11,500	10,911
Book value per share	22.56	21.73	20.89	20.20	19.21
Return on average common equity	10.2%	10.4%	9.5%	10.3%	10.3%
Ratio of earnings to fixed charges ^(d)	3.3	3.3	3.2	3.3	3.1
Non-GAAP:					
Ongoing earnings ^(e)	\$ 1,171	\$ 1,123	\$ 1,064	\$ 1,021	\$ 968
Ongoing diluted EPS ^(e)	2.30	2.21	2.09	2.03	1.95

^(a) 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.

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

^(c) Includes capital lease obligations.

^(d) See Exhibit 12.01.

^(e) See Item 7 for reconciliations of ongoing earnings and diluted EPS to GAAP earnings and diluted EPS.

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

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. Xcel Energy's operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with the TransCo subsidiaries, WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

Xcel Energy Inc.'s nonregulated subsidiaries are Eloigne and Capital Services. Eloigne invests in rental housing projects that qualify for low-income housing tax credits, and Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries.

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 2018 EPS guidance, the TCJA's impact to Xcel Energy and its customers, long-term earnings per share and dividend growth rate, as well as assumptions and other statements identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2017 (including 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 and Exhibit 99.01 hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth, recovery, trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; financial or regulatory accounting policies imposed by regulatory bodies; outcomes of regulatory proceedings; availability or cost of capital; and employee work force factors.

Management's Strategic Priorities

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

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

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

Lead the clean energy transition

For more than a decade, we have managed the risk of climate change and increasing customer demand for renewable energy through a clean energy strategy that consistently reduces carbon emissions and transitions our operations for the future. As a result, we have successfully reduced our carbon emissions by 35 percent from 2005 to 2017. We expect to reduce our carbon footprint by 45 percent by 2021 and by 60 percent by 2030 (over 2005 levels).

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

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

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

We have announced ambitious plans to add 3,680 MW of wind energy on our system by 2021. This includes:

- The 600 MW Rush Creek project in Colorado that is under construction and will be owned entirely by Xcel Energy;
- The 1,550 MW of wind generation in Minnesota and the Dakotas. This project has been approved by the MPUC and will include 1,150 MW of ownership and 400 MW of PPAs;
- The proposed 1,230 MW of wind projects in Texas and New Mexico, which includes 1,000 MW of ownership and 230 MW of PPAs; and
- The proposed 300 MW Dakota Range wind project in South Dakota.

In addition, the proposed CEP encompasses the retirement of 660 MW from two coal-fired units at Comanche and the potential addition of up to 1,000 MW of wind, 700 MW of solar and 700 MW of natural gas and/or storage.

Enhance the customer experience

The utility landscape is changing, and we must continue to thoughtfully anticipate and address the future needs of our stakeholders, including our customers, policymakers, employees and shareholders. Adapting to this changing environment is critical to our long-term success. Our customers expect to have choices, and we are committed to providing options and solutions that they want and value at a competitive price. Our continued investment in clean energy is an example of this commitment to our customers. Environmental stewardship remains foundational to Xcel Energy and our desire is to more broadly impact our customers and communities while creating shareholder value.

We will continue to expand our production of renewable energy, including wind and solar alternatives, and further develop and promote DSM, conservation and renewable programs. We are also in the process of transforming our transmission and distribution systems to accommodate increased levels of renewables, distributed energy resources and corresponding data growth, while maintaining high levels of reliability and security and keeping customer bills affordable. Finally, we are improving our communications to enable customers to interact with us in the way they prefer.

Keep bills low

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

Xcel Energy is working to keep O&M expense relatively flat without compromising reliability or safety. We intend to accomplish this objective by continually improving our processes, leveraging technology, proactively managing risk and maintaining a workforce that is prepared to meet the needs of our business today and tomorrow. As a result of these actions, Xcel Energy's 2017 O&M was lower than 2014 levels.

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

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

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

We have consistently achieved our financial objectives, meeting or exceeding our earnings guidance range for thirteen consecutive years, and we believe we are positioned to continue to deliver on our value proposition. Our ongoing earnings have grown approximately 5.9 percent and our dividend has grown approximately 4.4 percent annually from 2005 through 2017. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range, while our secured operating company debt ratings are in the A range. Although the TCJA placed pressure on our credit metrics, we are taking steps to retain the health of our credit ratings.

Responsible by nature

We understand the important role we play as a member of society: meeting a basic need, taking great care of the investments made in our company and engaging with our communities in ways that helps them thrive. We believe energy is a critical service for all people; one that enhances quality of life and enables economic progress. We know our investors and their customers are putting their faith in us to create economic value for them and their families over the long term, and we will continue to prepare for tomorrow to retain their trust in us. We exist because of the families, businesses and cities that rely on us, and we are privileged to serve them. We see our success not simply as a measure of profit but also as our broader impact on the public good.

Financial Review

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

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary as well as the ROE of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary, but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS and ongoing ROE for Xcel Energy and by subsidiary are financial measures not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing ROE is calculated by dividing the net income or loss attributable to the controlling interest of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average common stockholders' or stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as alternatives to measures calculated and reported in accordance with GAAP.

Results of Operations

The following tables summarize diluted EPS for Xcel Energy at Dec. 31:

Diluted Earnings (Loss) Per Share	2017			2016		2015	
	GAAP Diluted EPS	Impact of TCJA	Ongoing Diluted EPS	GAAP and Ongoing Diluted EPS	GAAP Diluted EPS	Loss on Monticello LCM/EPU Project	Ongoing Diluted EPS ^(b)
NSP-Minnesota	\$ 0.96	\$ 0.05	\$ 1.01	\$ 0.96	\$ 0.70	\$ 0.16	\$ 0.85
PSCo	0.97	(0.03)	0.94	0.91	0.92	—	0.92
SPS	0.31	(0.01)	0.30	0.30	0.25	—	0.25
NSP-Wisconsin	0.16	—	0.16	0.14	0.15	—	0.15
Equity earnings of unconsolidated subsidiaries ^(a)	0.07	(0.04)	0.03	0.05	0.04	—	0.04
Regulated utility ^(b)	\$ 2.47	\$ (0.03)	\$ 2.45	\$ 2.35	\$ 2.06	\$ 0.16	\$ 2.21
Xcel Energy Inc. and other	(0.22)	0.07	(0.15)	(0.15)	(0.11)	—	(0.11)
Total^(b)	\$ 2.25	\$ 0.05	\$ 2.30	\$ 2.21	\$ 1.94	\$ 0.16	\$ 2.09

(a) Includes income taxes.

(b) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation and when communicating its earnings outlook to analysts and investors.

2017 Adjustment to GAAP Earnings

Impact of the TCJA — Xcel Energy recognized an estimated one-time, non-cash, income tax expense of approximately \$23 million in the fourth quarter of 2017 for net excess deferred tax assets which may not be recovered from customers or not attributable to regulated operations, increased valuation allowances, etc. due to the enactment of the TCJA in December 2017. The income tax expense associated with the TCJA enactment has been excluded from Xcel Energy's 2017 ongoing earnings, given the non-recurring nature of the TCJA's broad and sweeping reform of the IRC. See Note 6 to the consolidated financial statements for further discussion.

2015 Adjustment to GAAP Earnings

Loss on Monticello LCM/EPU Project — In March 2015, the MPUC approved full recovery, including a return, on \$415 million of the project costs, inclusive of AFUDC, but only allowed recovery of the remaining \$333 million of costs with no return on this portion of the investment for 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately \$129 million, or \$79 million net of tax, in the first quarter of 2015. See Note 12 to the consolidated financial statements for further discussion.

Earnings Adjusted for Certain Items

2017 Comparison with 2016

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

NSP-Minnesota — GAAP earnings were flat for 2017. Ongoing earnings increased \$0.05 per share, excluding the impact of the TCJA. The change reflects higher electric margins driven by a 2017 Minnesota rate increase as well as increased gas margins, a lower ETR and reduced O&M expenses. The decrease in the ETR is largely driven by resolution of IRS appeals/audits and an increase in wind PTCs, which are flowed back to customers and reduce electric margin. Lower O&M expenses primarily relate to reduced expenses for nuclear refueling outages and overhauls at generation facilities. These positive factors were partially offset by higher depreciation expense due to increased invested capital as well as prior year amortization of Minnesota's excess depreciation reserve and higher property taxes.

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

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

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

Equity earnings of unconsolidated subsidiaries — GAAP earnings increased \$0.02 per share for 2017. Ongoing earnings of unconsolidated subsidiaries decreased \$0.02 per share, excluding the impact of the TCJA. The decline primarily related to lower revenues due to lower rates at our WYCO subsidiary, which develops and leases natural gas pipelines, storage and compression facilities.

2016 Comparison with 2015

Xcel Energy — 2016 GAAP earnings increased due to the 2015 loss on Monticello LCM/EPU project; see Note 12 for further information. Ongoing earnings increased \$0.12 per share (GAAP earnings increased \$0.28 per share). Increases in electric and natural gas margins were primarily driven by higher rates and riders across various jurisdictions to recover our capital investments and the favorable impact of weather as compared with the previous year. These positive factors and a lower ETR were partially offset by higher depreciation, interest charges and property taxes.

NSP-Minnesota — 2016 GAAP earnings increased due to the 2015 loss on Monticello LCM/EPU project; see Note 12 for further information. Ongoing earnings increased \$0.11 per share due to the following: higher electric margins primarily driven by an interim electric rate increase in Minnesota (net of estimated provision for refund); non-fuel riders; the favorable impact of weather; and a lower ETR. These positive factors were partially offset by higher depreciation, O&M expenses, interest charges and property taxes.

PSCo — Earnings decreased \$0.01 per share for 2016. The positive impact of higher natural gas margins (primarily due to a rate increase), sales growth and a lower estimated electric earnings test refund, were more than offset by increased depreciation and interest charges.

SPS — Earnings increased \$0.05 per share for 2016. Higher electric margins and lower O&M expenses were partially offset by an increase in depreciation and interest charges.

NSP-Wisconsin — Earnings decreased \$0.01 per share for 2016. The positive impact of higher electric margins (primarily driven by an electric rate increase) was more than offset by higher O&M expenses and depreciation.

Equity earnings of unconsolidated subsidiaries — Earnings of unconsolidated subsidiaries increased \$0.01 per share in 2016 due to facility expansion and increased revenue at WYCO.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. The decrease in earnings was primarily related to higher long-term debt levels.

Changes in Diluted EPS

The following tables summarize significant components contributing to the changes in 2017 EPS compared with the same period in 2016 and 2016 EPS compared with the same period in 2015:

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP and ongoing diluted EPS — 2016	\$ 2.21
Components of change — 2017 vs. 2016	
Higher electric margins ^(a)	0.16
Lower ETR ^(b)	0.07
Higher natural gas margins	0.03
Higher AFUDC — equity	0.03
Lower O&M expenses	0.03
Higher depreciation and amortization	(0.21)
Higher conservation and DSM program expenses ^(c)	(0.03)
Higher interest charges	(0.02)
Higher taxes (other than income taxes)	(0.02)
Equity earnings of unconsolidated subsidiaries	(0.02)
Other, net	0.02
GAAP diluted EPS — 2017	2.25
Impact of the TCJA	0.05
Ongoing diluted EPS — 2017	\$ 2.30

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

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

^(c) Offset by higher revenues.

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP diluted EPS — 2015	\$ 1.94
Loss on Monticello LCM/EPU project	0.16
Ongoing diluted EPS — 2015^(a)	2.09
Components of change — 2016 vs. 2015	
Higher electric margins	0.32
Lower ETR	0.06
Higher natural gas margins	0.04
Higher depreciation and amortization	(0.21)
Higher interest charges	(0.06)
Higher taxes (other than income taxes)	(0.02)
Other, net	(0.01)
GAAP and ongoing diluted EPS — 2016	\$ 2.21

(a) Amounts may not add due to rounding.

The following tables summarize the ROE for Xcel Energy and its utility subsidiaries at Dec. 31:

ROE — 2017	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Operating Companies	Xcel Energy
GAAP ROE	9.05%	8.90%	7.84%	9.41%	8.84%	10.21%
Impact of the TCJA	0.45	(0.24)	(0.30)	0.09	0.03	0.21
Ongoing ROE	<u>9.50%</u>	<u>8.66%</u>	<u>7.54%</u>	<u>9.50%</u>	<u>8.87%</u>	<u>10.42%</u>
ROE — 2016	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Operating Companies	Xcel Energy
GAAP and ongoing ROE	9.29%	8.92%	8.14%	8.63%	8.94%	10.39%

The following tables provide reconciliations of GAAP earnings (net income) to ongoing earnings and GAAP diluted EPS to ongoing diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2017	2016	2015
GAAP earnings	\$ 1,148	\$ 1,123	\$ 985
Estimated impact of TCJA	23	—	—
Loss on Monticello LCM/EPU project	—	—	79
Ongoing earnings	<u>\$ 1,171</u>	<u>\$ 1,123</u>	<u>\$ 1,064</u>
Diluted Earnings Per Share	2017	2016	2015
GAAP diluted EPS	\$ 2.25	\$ 2.21	\$ 1.94
Estimated impact of TCJA	0.05	—	—
Loss on Monticello LCM/EPU project	—	—	0.16
Ongoing diluted EPS^(a)	<u>\$ 2.30</u>	<u>\$ 2.21</u>	<u>\$ 2.09</u>

(a) Amounts may not add due to rounding.

Statement of Income Analysis

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

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (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. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (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 as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2015 vs. Normal	2016 vs. 2015
HDD	(10.0)%	(13.4)%	2.6%	(7.9)%	(5.5)%
CDD	6.5	11.1	(3.5)	6.2	5.1
THI	(11.3)	7.7	(18.5)	(2.3)	10.9

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with normal weather conditions:

	2017 vs. Normal	2016 vs. Normal	2017 vs. 2016	2015 vs. Normal	2016 vs. 2015
Retail electric	\$ (0.036)	\$ 0.004	\$ (0.040)	\$ (0.020)	\$ 0.024
Firm natural gas	(0.023)	(0.025)	0.002	(0.018)	(0.007)
Total (excluding decoupling)	\$ (0.059)	\$ (0.021)	\$ (0.038)	\$ (0.038)	\$ 0.017
Decoupling — Minnesota	0.022	(0.002)	0.024	—	(0.002)
Total (adjusted for recovery from decoupling)	\$ (0.037)	\$ (0.023)	\$ (0.014)	\$ (0.038)	\$ 0.015

Sales Growth (Decline) — The following tables summarize Xcel Energy and its utility subsidiaries' sales growth (decline) for actual and weather-normalized sales for the years ended Dec. 31, compared with the previous year:

	2017 vs. 2016				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential ^(a)	(2.1)%	(1.8)%	(3.5)%	(0.8)%	(2.1)%
Electric C&I	(1.4)	(0.1)	1.3	2.2	(0.1)
Total retail electric sales	(1.6)	(0.6)	0.2	1.3	(0.7)
Firm natural gas sales	9.3	(2.2)	N/A	11.3	2.1
	2017 vs. 2016				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential ^(a)	(0.7)%	(1.6)%	(1.2)%	0.3%	(1.0)%
Electric C&I	(1.0)	0.1	1.5	2.5	0.2
Total retail electric sales	(1.0)	(0.4)	0.9	1.8	(0.2)
Firm natural gas sales	4.7	0.6	N/A	5.7	2.2

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

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

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

(b) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 0.3 percent for retail electric and 0.5 percent for firm natural gas for the twelve months ended.

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

- NSP-Minnesota's residential sales decrease was a result of lower use per customer, partially offset by customer growth. The decline in commercial and industrial (C&I) sales was largely due to reduced usage, which offset an increase in the number of customers. Declines in services more than offset increased sales to large customers in manufacturing and energy industries.
- PSCo's decline in residential sales reflects lower use per customer, partially offset by customer additions. C&I growth was mainly due to an increase in customers and higher use for large C&I customers that support the mining, oil and natural gas industries, partially offset by lower use for the small C&I class.
- SPS' residential sales fell largely due to lower use per customer. The increase in C&I sales reflects customer additions and greater use for large C&I customers driven by the oil and natural gas industry in the Permian Basin.
- NSP-Wisconsin's residential sales increase was primarily attributable to higher use per customer and customer additions. C&I growth was largely due to higher use per customer and increased sales to customers in the sand mining industry and large customers in the energy and manufacturing industries.

Weather-normalized 2017 Natural Gas Sales Growth (Excluding Leap Day)

- Across service territories, higher natural gas sales reflect an increase in the number of customers, partially offset by a decline in customer use.

Weather-normalized sales for 2018 are projected to be within a range of 0 percent to 0.5 percent over 2017 levels for retail electric customers and 0 percent to 0.5 percent below 2017 levels for firm natural gas customers.

	2016 vs. 2015				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential ^(a)	1.2%	1.8%	(1.6)%	0.3%	0.9%
Electric C&I	(0.5)	(0.4)	1.1	(0.1)	—
Total retail electric sales	—	0.4	0.7	(0.1)	0.3
Firm natural gas sales	(4.1)	(1.1)	N/A	(7.4)	(2.4)

	2016 vs. 2015				
	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential ^(a)	0.1%	1.9%	(1.3)%	(0.2)%	0.5%
Electric C&I	(0.8)	(0.4)	0.8	(0.2)	(0.3)
Total retail electric sales	(0.5)	0.4	0.5	(0.3)	—
Firm natural gas sales	(0.3)	(0.2)	N/A	(4.3)	(0.5)

2016 vs. 2015 (Excluding Leap Day) ^(b)

	NSP-Minnesota	PSCo	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized - adjusted for leap day					
Electric residential ^(a)	(0.2)%	1.6%	(1.6)%	(0.6)%	0.3%
Electric C&I	(1.0)	(0.7)	0.5	(0.5)	(0.5)
Total retail electric sales	(0.8)	0.1	0.2	(0.6)	(0.3)
Firm natural gas sales	(0.8)	(0.7)	N/A	(4.8)	(1.0)

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

(b) The estimated impact of the 2016 leap day is excluded to present a more comparable year-over-year presentation. The estimated impact of the additional day of sales in 2016 was approximately 0.2 percent to 0.4 percent for retail electric and 0.5 percent for firm natural gas for the twelve months ended.

Weather-normalized 2016 Electric Sales Growth (Decline) (Excluding Leap Day)

- NSP-Minnesota's residential sales decreased as a result of lower use per customer, partially offset by customer additions. C&I sales declined primarily as a result of lower use by customers in the manufacturing and service industries.
- PSCo's residential growth reflects an increased number of customers. The C&I decline was mainly due to lower sales to certain large customers in the manufacturing, mining, oil and gas industries. The decline was partially offset by an increase in the number of small C&I customers.
- SPS' residential sales decline was primarily the result of lower use per customer, partially offset by an increased number of customers. The increase in C&I sales was driven by energy sector expansion in the Southeastern New Mexico, Permian Basin area as well as greater use by agricultural customers.
- NSP-Wisconsin's residential sales decrease was primarily attributable to lower use per customer, partially offset by customer additions. The C&I decline was largely due to reduced sales to small customers. The overall decrease was partially offset by an increase in the number of C&I customers as well as greater use in the large C&I class for the oil and gas industries.

Weather-normalized 2016 Natural Gas Sales Decline (Excluding Leap Day)

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use, partially offset by a slight increase in the number of customers.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuation 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. The following table details the electric revenues and margin:

(Millions of Dollars)	2017	2016	2015
Electric revenues	\$ 9,676	\$ 9,500	\$ 9,276
Electric fuel and purchased power	(3,757)	(3,718)	(3,763)
Electric margin	\$ 5,919	\$ 5,782	\$ 5,513

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

Electric Revenues

(Millions of Dollars)	2017 vs. 2016
Retail rate increases (Texas, Minnesota, New Mexico and Wisconsin)	\$ 123
Non-fuel riders	33
Conservation and DSM program revenues (offset by expenses)	23
Decoupling (weather portion — Minnesota)	18
Wholesale transmission revenue	10
Estimated impact of weather	(30)
Conservation incentive	(18)
Other, net	17
Total increase in electric revenues	\$ 176

Electric Margin

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

Electric Revenues

(Millions of Dollars)	2016 vs. 2015
Retail rate increases ^(a)	\$ 190
Transmission revenue	71
Trading	40
Non-fuel riders	28
Estimated impact of weather, excluding decoupling in Minnesota	19
Fuel and purchased power cost recovery	(127)
Other, net	3
Total increase in electric revenues	<u>\$ 224</u>

^(a) Increase is primarily due to interim rates in Minnesota (net of estimated provision for refund) and final rates in Wisconsin and New Mexico.

Electric Margin

(Millions of Dollars)	2016 vs. 2015
Retail rate increases ^(a)	\$ 190
Non-fuel riders	28
Estimated impact of weather, excluding decoupling in Minnesota	19
Transmission revenue, net of costs	14
Retail sales growth, excluding weather impact	9
PSCo earnings test refunds	6
Conservation incentive	3
Firm wholesale	(12)
Other, net	12
Total increase in electric margin	<u>\$ 269</u>

^(a) Increase is primarily due to interim rates in Minnesota (net of estimated provision for refund) and final rates in Wisconsin and New Mexico.

Natural Gas Revenues and Margin

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

(Millions of Dollars)	2017	2016	2015
Natural gas revenues	\$ 1,650	\$ 1,531	\$ 1,672
Cost of natural gas sold and transported	(823)	(733)	(905)
Natural gas margin	<u>\$ 827</u>	<u>\$ 798</u>	<u>\$ 767</u>

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

Natural Gas Revenues

(Millions of Dollars)	2017 vs. 2016
Purchased natural gas adjustment clause recovery	\$ 88
Infrastructure and integrity riders	18
Conservation and DSM program revenues (offset by expenses).	7
Retail sales growth, excluding weather impact	7
Estimated impact of weather	1
Other, net	(2)
Total increase in natural gas revenues	<u>\$ 119</u>

Natural Gas Margin

(Millions of Dollars)	2017 vs. 2016
Infrastructure and integrity riders	\$ 18
Retail sales growth, excluding weather impact	7
Estimated impact of weather	1
Other, net	3
Total increase in natural gas margin	<u>\$ 29</u>

Natural Gas Revenues

(Millions of Dollars)	2016 vs. 2015
Purchased natural gas adjustment clause recovery	\$ (177)
Estimated impact of weather	(5)
Infrastructure and integrity riders	(5)
Retail rate increases (Colorado).	36
Conservation and DSM program revenues (offset by expenses).	8
Other, net	2
Total decrease in natural gas revenues	<u>\$ (141)</u>

Natural Gas Margin

(Millions of Dollars)	2016 vs. 2015
Retail rate increases (Colorado).	\$ 36
Conservation and DSM program revenues (offset by expenses).	8
Estimated impact of weather	(5)
Infrastructure and integrity riders	(5)
Other, net	(3)
Total increase in natural gas margin	<u>\$ 31</u>

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased \$23 million, or 1.0 percent, for 2017 compared with 2016. The significant changes are summarized in the table below:

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

- Nuclear plant operations and amortization expenses are lower mostly due to reduced refueling outage costs and operating efficiencies;
- Plant generation costs decreased as a result of lower expenses associated with planned outages and overhauls at a number of generation facilities; and
- Employee benefits expense includes the recognition of an \$8 million pension settlement expense in the fourth quarter of 2017.

O&M expenses decreased \$4 million, or 0.1 percent for 2016 compared with 2015.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased \$28 million, or 11.4 percent, for 2017 compared with 2016. The increase was due to higher customer participation in electric conservation programs and recovery rates, mostly in Minnesota. Conservation and DSM expenses, including incentives, are generally recovered in our major jurisdictions concurrently through riders and base rates. Timing of recovery may not correspond to the period in which costs were incurred.

Conservation and DSM program expenses increased \$20 million, or 8.9 percent, for 2016 compared with 2015. The increase is primarily attributable to more customer participation in DSM programs.

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

Depreciation and amortization increased \$179 million, or 15.9 percent, for 2016 compared with 2015. The increase was primarily attributable to capital investments, including Pleasant Valley and Border Wind Farms, reduction of the excess depreciation reserve in Minnesota and recognition of the DOE settlement credits in 2015.

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

Taxes (other than income taxes) increased \$20 million, or 4.0 percent, for 2016 compared with 2015. The increase was primarily due to higher property taxes in Minnesota, excluding the impact of the tax deferral related to the Minnesota 2016 multi-year electric rate case.

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

AFUDC increased \$5 million for 2016 compared with 2015. The increase was primarily due to the expansion of transmission facilities and other capital expenditures.

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

Interest charges increased \$52 million, or 8.7 percent, for 2016 compared with 2015. The increase was related to higher long-term debt levels to fund capital investments, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense decreased \$39 million for 2017 compared with 2016. The decrease was primarily driven by increased wind PTCs, a net tax benefit related to the resolution of appeals/audits in 2017, an increase in research and experimentation credits, lower pretax earnings in 2017 and a rise in permanent plant-related adjustments. PTCs are flowed back to customers and reduce electric margin. The decrease was partially offset by the estimated one-time, non-cash, income tax expense recognized in the fourth quarter related to the TCJA. The ETR was 32.1 percent for 2017 compared with 34.1 percent for 2016. The lower ETR in 2017 was primarily due to the adjustments referenced above. Excluding the impact for the TCJA adjustment, the ETR would have been 30.7 percent for 2017. See Note 6 to the consolidated financial statements for further discussion.

Income tax expense increased \$38 million for 2016 compared with 2015. The increase in income tax expense was primarily due to higher pretax earnings in 2016, partially offset by increased wind PTCs in 2016. The ETR was 34.1 percent for 2016 compared with 35.5 percent for 2015. The lower ETR was primarily due to the wind PTCs in 2016.

Xcel Energy Inc. and Other Results

The following tables summarize the net income and diluted EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

(Millions of Dollars)	Contribution to Xcel Energy's Earnings		
	2017	2016	2015
Xcel Energy Inc. financing costs	\$ (79)	\$ (71)	\$ (56)
Eloigne ^(a)	2	1	—
Xcel Energy Inc. taxes and other results	(35)	(6)	(3)
Total Xcel Energy Inc. and other costs	<u>\$ (112)</u>	<u>\$ (76)</u>	<u>\$ (59)</u>
	Contribution to Xcel Energy's GAAP diluted EPS		
	2017	2016	2015
Diluted Earnings (Loss) Per Share			
Xcel Energy Inc. financing costs	\$ (0.15)	\$ (0.14)	\$ (0.11)
Eloigne ^(a)	—	—	—
Xcel Energy Inc. taxes and other results	(0.07)	(0.01)	—
Total Xcel Energy Inc. and other costs	<u>\$ (0.22)</u>	<u>\$ (0.15)</u>	<u>\$ (0.11)</u>

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

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

Factors Affecting Results of Operations

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

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. While economic growth has been improving over the past year, management cannot predict whether this trend will be sustained going forward. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates.

Fuel Supply and Costs

Xcel Energy Inc.'s operating utilities have varying dependence on coal, natural gas and uranium. Changes in commodity prices are generally recovered through fuel recovery mechanisms and have very little impact on earnings. However, availability of supply, the potential implementation of a carbon tax or emissions-related generation restrictions and unanticipated changes in regulatory recovery mechanisms could impact our operations. See Item 1 for further discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

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

Tax Reform

On Dec. 22, 2017, the TCJA was signed by the President, enacting significant changes to the IRC. The changes are generally effective for Xcel Energy federal tax returns for years following 2017, and include a reduction in the federal corporate income tax rate from 35 percent to 21 percent. The TCJA recognizes the unique nature of public utilities and contains certain provisions specific to the industry, including continuing certain interest expense deductibility and not allowing 100 percent expensing of capital investments.

2017 Impacts of Tax Reform

- Required the revaluation of federal deferred tax assets and liabilities using the new lower tax rate. The majority of the revaluation relates to regulated utility activities and results in the recording of regulatory assets and liabilities, with no estimated income statement impact; and
- Xcel Energy recognized approximately \$23 million of income tax expense associated with the TCJA in the fourth quarter of 2017. This amount is considered to be non-recurring and has been excluded from Xcel Energy’s 2017 ongoing earnings.

Future Impacts of Tax Reform

- Decreases annual revenue requirements by approximately \$400 million;
- Reduces the tax benefit from holding company interest expense by approximately \$20 million in 2018, negatively impacting earnings;
- Increases rate base growth for the same level of expected capital expenditures due to lower forecasted deferred tax liabilities; and
- Negative impact on cash flow from operations and credit metrics, depending on regulatory actions.

Potential Regulatory Options

The timing of revenue requirements adjustments for both the return of excess deferred taxes and the lower tax rate are subject to regulatory actions in each of the eight states in which the regulated utilities operate, as well as the FERC. Each regulatory jurisdiction has initiated active proceedings to reflect the impacts of TCJA. In addition to lower revenue requirements, the TCJA also reduces the pre-tax credit that our customers receive from the federal PTCs; this issue will be reviewed in various resource planning and asset acquisition proceedings. Additionally, Xcel Energy has open rate cases and resource acquisition dockets pending in several states that may be impacted.

Xcel Energy plans to work directly with its regulators to determine the appropriate path forward in each jurisdiction. Potential regulatory options that may be appropriate to consider either as alternatives to or in a combination with flowing back the lower revenue requirements through rates include, but are not limited to:

- Accelerating depreciation or amortization for selected assets or asset classes;
- Increasing authorized equity ratios at the operating company level;
- Modifying capital investments;
- Avoiding or deferring future rate cases; and
- Funding of certain long-dated obligations.

Xcel Energy believes that regulatory actions that include higher authorized operating company equity ratios and/or accelerated depreciation/amortization can preserve operating company credit metrics that otherwise degrade under the TCJA.

See Notes 6 and 12 to the consolidated financial statements for further discussion.

Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries, TransCo subsidiaries and WGI. Decisions by these regulators can significantly impact Xcel Energy's results of operations. Xcel Energy expects to periodically file for rate changes based on changing operating costs, new or planned investments, fluctuations in energy markets and general economic conditions.

The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Rates charged by Xcel Energy Inc.'s TransCo subsidiaries and WGI are approved by the FERC. Xcel Energy Inc.'s utility subsidiaries request changes in rates for utility services through filings with the governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of filing general rate cases and the implementation of final rates. In addition to changes in operating costs, 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.

Wholesale Energy Market Regulation — Wholesale energy markets are operated by MISO in the Midwest and SPP in the South Central U.S. to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. NSP-Minnesota and NSP-Wisconsin are members of MISO and SPS is a member of SPP. NSP-Minnesota, NSP-Wisconsin and SPS expect to recover RTO energy and other charges through either base rates or various recovery mechanisms. PSCo is evaluating participation in the SPP RTO energy market through the MWTG. See Item 1 and Note 12 to the consolidated financial statements for further discussion.

Capital Expenditure Regulation — Xcel Energy Inc.'s utility subsidiaries make substantial investments in renewable generation, plant additions to build and upgrade power plants, and expand and maintain the energy transmission and distribution systems. Xcel Energy Inc.'s utility subsidiaries to recover the costs associated with capital investments through rate case filings and through riders (in certain states). These non-fuel rate riders are expected to provide cash flows to enable recovery of costs incurred on a more timely basis. Xcel Energy has implemented formula rates for each of the utility subsidiaries that will provide annual rate changes as transmission or production investments increase in a manner similar to the retail rate riders for wholesale electric transmission and production services. Electric transmission investments owned by the TransCos are recoverable through FERC approved transmission formula rates for XETD and XEST. NSP-Minnesota and NSP-Wisconsin have no cost-based wholesale production customers and therefore have not implemented a production formula rate.

Environmental Matters

Environmental costs include accruals for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions. A trend of greater environmental awareness and increasingly stringent regulation may continue to cause higher operating expenses and capital expenditures for environmental compliance.

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

- \$303 million in 2017;
- \$304 million in 2016; and
- \$292 million in 2015.

Xcel Energy estimates an average annual expense of approximately \$349 million from 2018 through 2022 for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- \$61 million in 2017;
- \$93 million in 2016; and
- \$184 million in 2015.

See Item 7 — Capital Requirements for further discussion.

Xcel Energy's operations are subject to federal and state laws and regulations related to air emissions, water discharges and waste management from various sources. Such laws and regulations impose monitoring and reporting requirements and may require Xcel Energy to obtain pre-approval for the construction or modification of projects that increase air emissions, water discharges or land disposal of wastes, obtain and comply with permits that contain emission, discharge and operational limitations, or install or operate pollution control equipment at facilities. Xcel Energy will likely be required to incur capital expenditures in the future to comply with these requirements for remediation of MGP and other legacy sites and various regulations for air emissions, water intake and discharge and waste disposal. Actual expenditures could vary from the estimates presented. The scope and timing of these expenditures cannot be determined until any new or revised regulations become final or until more information is learned about the need for remediation at the legacy sites.

Pollution control equipment can be required by federal and state regulations, such as those requiring mercury emission reductions, and by state or federal implementation plans, such as those to address visibility impairment, interstate air pollution impacts or attainment of NAAQS. In 2016, the EPA adopted a federal visibility plan for Texas which imposes SO₂ emission limitations that reflect installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by early 2021. This rule has been stayed by the Fifth Circuit. In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, while leaving the stay in effect. The Fifth Circuit is now holding the case in abeyance until the EPA completes its reconsideration of the rule.

See Note 13 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. However, potential future inflation could result from economic conditions or the economic and monetary policies of the U.S. Government and the Federal Reserve. This could lead to future price increases for materials and services required to deliver electric and natural gas services to customers. These potential cost increases could in turn lead to increased prices to customers. Likewise, lower oil and natural gas prices could lead to sustained deflation, that could also reduce general economic activity although it may lead to lower electric and natural gas prices to customers. Additionally, under statute, federal agencies such as the FERC now can adjust statutory penalties for inflation.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported. The following is a list of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy Inc. is a holding company with rate-regulated subsidiaries that are 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 the competitive environment makes it probable that such rates will be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or OCI.

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

As of Dec. 31, 2017 and 2016, Xcel Energy has recorded regulatory assets of \$3.4 billion for both periods, and regulatory liabilities of \$5.3 billion and \$1.6 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. 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 15 to the consolidated financial statements for further discussion of regulatory assets and liabilities and Note 12 to the consolidated financial statements for further discussion of rate matters.

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 the 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. The TCJA reduced the federal income tax rate from 35 percent to 21 percent, significantly impacting the recorded amounts of deferred tax assets and liabilities and reducing the ETR applicable to future periods. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Tax Reform and Notes 6 and 12 to the consolidated financial statements for further discussion.

ETRs are highly impacted by assumptions. ETR calculations are revised every quarter based on best available year-end tax assumptions (income levels, deductions, credits, etc.); adjusted in the following year after returns are filed, with the tax accrual estimates being trued-up to the actual amounts claimed on the tax returns; and further adjusted after examinations by taxing authorities have been completed.

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. The change in the unrecognized tax benefits needs to be reasonably estimated based on evaluation of the nature of uncertainty, the nature of event that could cause the change and an estimated range of reasonably possible changes.

Management will use prudent business judgment to derecognize appropriate amounts of tax benefits at any period end, and as new developments occur. Unrecognized tax benefits can be recognized as issues are favorably resolved and loss exposures decline. We may adjust our unrecognized tax benefits and interest accruals to the updated estimates as disputes with the IRS and state tax authorities are resolved. These adjustments may increase or decrease earnings. See Note 6 to the consolidated financial statements for further discussion.

Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension and postretirement health care investment assets are expected to earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation. In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. See Note 9 to the consolidated financial statements for further discussion on the rate of return and discount rate used in the calculation of pension costs and obligations.

Pension costs are expected to decrease in 2018 and continue to decline in the following few years. Funding requirements in 2018 are expected to be consistent with 2017 and continue at that level in the following years. While investment returns were below the assumed levels in 2015 and 2016, investment returns exceeded the assumed levels in 2017. 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 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees, which was approximately 12 years in 2017.

Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be \$119 million in 2018 and \$105 million in 2019, while the actual pension costs were \$139 million in 2017 and \$122 million in 2016. The expected decrease in 2018 and future year costs is due primarily to reductions in loss amortizations, plan design changes and an increase in expected return on assets due to planned future contributions and expected return of current assets.

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

At Dec. 31, 2017, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87 percent, which is consistent with the rate set at Dec. 31, 2016. The rate of return used to measure postretirement health care costs is 5.80 percent at Dec. 31, 2017 and this is consistent with Dec. 31, 2016. Xcel Energy's ongoing pension investment strategy is based on plan-specific investments that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investments result in a greater percentage of interest rate sensitive 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.

Xcel Energy set the discount rates used to value the Dec. 31, 2017 pension at 3.63 percent and postretirement health care obligations at 3.62 percent, which represents a 50 basis point and a 51 basis point decrease from Dec. 31, 2016, respectively. 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. At Dec. 31, 2017, this reference point supported the selected rate. In addition to this reference point, Xcel Energy also reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

The following are the pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2015 through 2018:

- \$150 million in January 2018;
- \$162 million in 2017;
- \$125 million in 2016; and
- \$90 million in 2015.

For future years, we anticipate contributions will be made as necessary. These contributions are summarized in Note 9 to the consolidated financial statements. Future year amounts are estimates and 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.

If Xcel Energy were to use alternative assumptions at Dec. 31, 2017, a one-percent change would result in the following impact on 2017 pension costs:

(Millions of Dollars)	Pension Costs	
	+1%	-1%
Rate of return	\$ (17)	\$ 18
Discount rate ^(a)	(6)	9

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

Beginning with the Dec. 31, 2017 measurement date, Xcel Energy separated its initial medical trend assumption for pre-Medicare (Pre-65) and post-Medicare (Post-65) claims costs, and assumed 7.0 percent and 5.5 percent, respectively. Xcel Energy separated the trends in order to reflect different short-term expectations based on recent experiences with Pre-65 and Post-65 claims cost increases for Xcel Energy's retiree medical plan. The ultimate trend assumption remained at 4.5 percent for both Pre-65 and Post-65 claims costs as similar long-term trend rates are expected for both populations. The period from initial trend rate until the ultimate rate is reached is five years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

- Xcel Energy contributed \$20 million, \$18 million and \$18 million during 2017, 2016 and 2015, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately \$12 million during 2018.

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

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions as calculated 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 2017, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2017 pension settlement accounting expense.
- 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.

See Note 9 to the consolidated financial statements for further discussion.

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 various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions used to estimate AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset. Xcel Energy accretes ARO liabilities 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 total obligation for nuclear decommissioning is expected to be funded by the external decommissioning trust fund. The difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized under current accounting guidance is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were \$1.874 billion and \$2.249 billion as of Dec. 31, 2017 and 2016, respectively. Based on their significance, the following discussion relates specifically to the AROs associated with nuclear decommissioning.

NSP-Minnesota obtains periodic cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. These independent cost studies are based on relevant information available at the time performed. Estimates of future cash flows for extended periods of time are by nature 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 over the decommissioning period of the nuclear plants, including decontamination and removal of radioactive material. The MPUC approved NSP-Minnesota's currently effective decommissioning filing in October 2015. The most recent filing was submitted in December 2017 and is currently pending with the MPUC, with an order expected in 2018. See Note 13 for further discussion.

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

- **Timing** — Decommissioning cost estimates are impacted by each facility's retirement date and the expected timing of the actual decommissioning activities. Currently, the 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. By utilizing this method, 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 and experience as well as changes in regulations regarding nuclear decommissioning could cause cost estimates to change significantly. NSP-Minnesota's most recent nuclear decommissioning filing assumed current technology and regulations.
- **Escalation Rates** — Escalation rates represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities. NSP-Minnesota used an escalation rate of 3.42 percent in calculating the ARO related to nuclear decommissioning for the Monticello facility, a rate of 3.40 percent for PI Unit 1, and a rate of 3.40 percent for PI Unit 2. These rates are weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.
- **Discount Rates** — Changes in timing or estimated expected 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 four to seven percent have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating the future cost of nuclear decommissioning including the method to be utilized, the ultimate costs to decommission, and the 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.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many 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 the events and 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, 2017.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 11 to the consolidated financial statements for further discussion of market risks associated with derivatives.

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

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

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

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

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

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

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

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

2 — Prices based on models and other valuation methods.

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

(Millions of Dollars)	2017	2016
Fair value of commodity trading net contract assets outstanding at Jan. 1	\$ 10	\$ 11
Contracts realized or settled during the period	(5)	(5)
Commodity trading contract additions and changes during the period	11	4
Fair value of commodity trading net contract assets outstanding at Dec. 31	<u>\$ 16</u>	<u>\$ 10</u>

At Dec. 31, 2017, a 10 percent increase or decrease in market prices for commodity trading contracts would have an immaterial impact. At Dec. 31, 2016, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income from continuing operations by approximately \$1 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately \$1 million.

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

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

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

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 58 percent of its 2018 and approximately 24 percent of its 2019 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. Alternate potential sources are expected to provide the flexibility to manage NSP-Minnesota’s nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 35 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material.

Separately, NSP-Minnesota has enriched nuclear fuel materials in process with Westinghouse Electric Corporation (Westinghouse). Westinghouse filed for Chapter 11 bankruptcy protection in March 2017. NSP-Minnesota owns materials in Westinghouse’s inventory and has contracts in place under which Westinghouse will provide certain services during an upcoming outage at Prairie Island (PI). Westinghouse will provide nuclear fuel assemblies for the upcoming PI outage under the current nuclear fuel fabrication contract. Westinghouse has indicated its intention to continue to perform under the arrangements. Based on Westinghouse’s stated intent and the interim financing secured to fund its on-going operations, NSP-Minnesota does not expect the bankruptcy to materially impact NSP-Minnesota’s operational or financial performance. Westinghouse announced on Jan. 4, 2018 it has agreed to be acquired by Brookfield Business Partners LP and other institutional partners. Brookfield’s acquisition of Westinghouse is expected to close in the third quarter of 2018, subject to bankruptcy court and regulatory approvals. NSP-Minnesota will continue to monitor the Westinghouse acquisition process.

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

At Dec. 31, 2017 and 2016, a 100 basis point change in the benchmark rate on Xcel Energy’s variable rate debt would impact annual pretax interest expense by approximately \$9 million and \$4 million, respectively. See Note 11 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries’ interest rate derivatives.

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. At Dec. 31, 2017, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, 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, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets as well as benefit costs. For further information, see “Employee Benefits” under Critical Accounting Policies and Estimates.

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

At Dec. 31, 2017, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of \$26 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$7 million. At Dec. 31, 2016, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of \$6 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of \$17 million.

Xcel Energy Inc. and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy’s credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 11 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2017. 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 deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2017.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forward and option contracts that are long-term in nature or relate to inactive delivery locations. Level 3 commodity derivative assets and liabilities represent 1.7 percent and 4.3 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2017.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included \$32 million and \$2 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2017.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts for inactive delivery locations and for contracts that extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were \$5 million in Level 3 commodity derivative assets and no liabilities for options held at Dec. 31, 2017. There were immaterial Level 3 commodity derivative assets and liabilities for forwards held at Dec. 31, 2017.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2017	2016	2015
Net cash provided by operating activities	\$ 3,126	\$ 3,052	\$ 3,038

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

Net cash provided by operating activities increased by \$14 million for 2016 as compared to 2015. The increase was primarily due to timing of vendor payments and higher net income, excluding amounts related to non-cash operating activities (e.g., depreciation, deferred tax expenses and a charge related to the Monticello LCM/EPU project in 2015), partially offset by timing of customer receipts, refunds and recovery of certain electric and natural gas riders and incentive programs.

(Millions of Dollars)	2017	2016	2015
Net cash used in investing activities	\$ (3,296)	\$ (3,261)	\$ (3,623)

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

Net cash used in investing activities decreased by \$362 million for 2016 as compared to 2015. The decrease was primarily attributable to the acquisition of two wind projects in 2015, partially offset by the establishment of rabbi trusts in 2016 and higher insurance proceeds received in 2015.

(Millions of Dollars)	2017	2016	2015
Net cash provided by financing activities	\$ 168	\$ 209	\$ 590

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

Net cash provided by financing activities decreased by \$381 million for 2016 as compared to 2015. The decrease was primarily due to higher repayments of long-term and short-term debt, higher dividend payments and repurchases of common stock, partially offset by higher debt issuances in 2016.

See discussion of trends, commitments and uncertainties, and the potential future impact on cash flow and liquidity under Capital Sources.

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.

Capital Expenditures — The current estimated base capital expenditure programs of Xcel Energy’s operating companies for the years 2018 through 2022 are shown in the table below:

(Millions of Dollars)	Capital Forecast					2018 - 2022 Total
	2018	2019	2020	2021	2022	
By Subsidiary						
NSP-Minnesota	\$ 1,370	\$ 1,910	\$ 1,450	\$ 1,590	\$ 1,500	\$ 7,820
PSCo.	1,650	1,020	950	1,150	1,410	6,180
SPS	1,020	1,140	710	470	540	3,880
NSP-Wisconsin.	250	250	240	280	290	1,310
Other ^(a)	20	(90)	(90)	(30)	—	(190)
Estimated capital reduction ^(b)	(100)	(100)	(100)	(100)	(100)	(500)
Total capital expenditures	<u>\$ 4,210</u>	<u>\$ 4,130</u>	<u>\$ 3,160</u>	<u>\$ 3,360</u>	<u>\$ 3,640</u>	<u>\$ 18,500</u>

(Millions of Dollars)	Capital Forecast					2018 - 2022 Total
	2018	2019	2020	2021	2022	
By Function						
Electric distribution	\$ 750	\$ 810	\$ 870	\$ 1,110	\$ 1,380	\$ 4,920
Renewables.	1,410	1,860	880	270	—	4,420
Electric transmission	770	540	570	860	980	3,720
Electric generation	520	370	290	520	530	2,230
Natural gas	460	400	410	420	510	2,200
Other ^(c)	400	250	240	280	340	1,510
Estimated capital reduction ^(b)	(100)	(100)	(100)	(100)	(100)	(500)
Total capital expenditures	<u>\$ 4,210</u>	<u>\$ 4,130</u>	<u>\$ 3,160</u>	<u>\$ 3,360</u>	<u>\$ 3,640</u>	<u>\$ 18,500</u>

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

(b) Xcel Energy has reduced its capital forecast by \$500 million due to the potential impact of tax reform on cash flows and credit metrics.

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

The base capital expenditure forecast does not include the CEP, which if approved could increase the total capital investment by up to \$1.5 billion, based on a preliminary estimate. The level of capital investment may decline due to lower renewable pricing and the ultimate composition of assets selected as part of the RFP process. The expected cost and potential capital investment of the CEP will be determined once a recommended portfolio is filed with the CPUC.

The capital expenditure programs of Xcel Energy are subject to continuing 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, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities.

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

Contractual Obligations and Other Commitments — In addition to its capital expenditure programs, Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2017. See the statements of capitalization and additional discussion in Notes 4 and 13 to the consolidated financial statements.

(Millions of Dollars)	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments ^(a)	\$ 25,510	\$ 1,073	\$ 2,808	\$ 2,368	\$ 19,261
Capital lease obligations	302	15	28	26	233
Operating leases ^{(b)(c)}	3,123	238	528	527	1,830
Unconditional purchase obligations ^(d)	7,367	1,596	1,965	1,565	2,241
Other long-term obligations, including current portion ^(e)	111	43	57	11	—
Payments to vendors in process	322	322	—	—	—
Short-term debt	814	814	—	—	—
Total contractual cash obligations ^{(f)(g)(h)}	\$ 37,549	\$ 4,101	\$ 5,386	\$ 4,497	\$ 23,565

- (a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2017, and outstanding principal for each investment with the terms ending at each instrument's maturity.
- (b) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2017, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately \$28 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.
- (c) Included in operating lease payments are \$213 million, \$474 million, \$481 million and \$1.7 billion, for the less than 1 year, 1-3 years, 3-5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.
- (d) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. Certain contractual purchase obligations are adjusted on indices. The effects of price changes are mitigated through cost of energy adjustment mechanisms.
- (e) Other long-term obligations relate primarily to amounts associated with technology agreements as well as uncertain tax positions.
- (f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately \$4.8 billion of goods and services through the year 2037, in addition to the amounts disclosed in this table.
- (g) In January 2018, contributions of \$150 million were made across four of Xcel Energy's pension plans. Obligations of this type are dependent on several factors, including management discretion and various minimum contribution requirements determined by the Pension Protection Act, and therefore, are not included in the table.
- (h) Xcel Energy expects to contribute approximately \$12 million to the postretirement health care plans during 2018. Obligations of this type are dependent on several factors, including management discretion, and therefore, are not included in the table.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2018, Xcel Energy announced a quarterly dividend of \$0.38 per share, which represents an increase of 5.6 percent. 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 certain 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 4 to the consolidated financial statements for further discussion of restrictions on dividend payments.

Regulation of Derivatives — In 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. The CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at \$8 billion, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. The de minimis threshold is scheduled to be reduced to \$3 billion in 2018. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that exempt certain derivatives end users from much of the clearing and margin requirements and Xcel Energy's Board of Directors has renewed the end-user exemption on an annual basis. Xcel Energy is currently meeting all reporting requirements and transaction restrictions.

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.

The funded status and pension assumptions are summarized in the following tables:

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Fair value of pension assets	\$ 3,088	\$ 2,856
Projected pension obligation ^(a)	3,828	3,682
Funded status	<u>\$ (740)</u>	<u>\$ (826)</u>

^(a) Excludes nonqualified plan of \$37 million and \$44 million at Dec. 31, 2017 and 2016, respectively.

Pension Assumptions	2017	2016
Discount rate	3.63%	4.13%
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 in large part 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. At Dec. 31, 2017 and 2016, there was \$3 million and \$4 million of cash held in these accounts, respectively.

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

- \$1 billion for Xcel Energy Inc.;
- \$700 million for PSCo;
- \$500 million for NSP-Minnesota;
- \$400 million for SPS; and
- \$150 million for NSP-Wisconsin.

In addition, Xcel Energy Inc. has a 364-day term loan agreement to borrow up to \$500 million. At Dec. 31, 2017, Xcel Energy Inc. had drawn \$250 million on the term loan.

Short-term debt outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2017
Borrowing limit	\$ 3,250
Amount outstanding at period end	814
Average amount outstanding	560
Maximum amount outstanding	814
Weighted average interest rate, computed on a daily basis	1.63%
Weighted average interest rate at end of period	1.90

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Borrowing limit	\$ 3,250	\$ 2,750	\$ 2,750
Amount outstanding at period end	814	392	846
Average amount outstanding	644	485	601
Maximum amount outstanding	1,247	1,183	1,360
Weighted average interest rate, computed on a daily basis	1.35%	0.74%	0.48%
Weighted average interest rate at end of period	1.90	0.95	0.82

Credit Agreements — Xcel Energy Inc., NSP-Minnesota, PSCo, and SPS each have the right to request an extension of the revolving credit facility June 2021 termination date for two additional one-year periods. 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.

Xcel Energy Inc. entered into a 364-Day Term Loan Agreement on Dec. 5, 2017 to borrow up to \$500 million. As of Dec. 31, 2017, Xcel Energy Inc. had borrowed \$250 million of the Term Loan. Xcel Energy Inc. may recommit for one additional 364-day period from the December 2018 maturity date, subject to majority consent from lenders.

As of Feb. 20, 2018, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility ^(a)	Drawn ^(b)	Available	Cash	Liquidity
Xcel Energy Inc.	\$ 1,500	\$ 877	\$ 623	\$ —	\$ 623
PSCo	700	21	679	1	680
NSP-Minnesota	500	81	419	2	421
SPS	400	31	369	1	370
NSP-Wisconsin	150	3	147	1	148
Total.	<u>\$ 3,250</u>	<u>\$ 1,013</u>	<u>\$ 2,237</u>	<u>\$ 5</u>	<u>\$ 2,242</u>

^(a) These credit facilities mature in June 2021, with the exception of Xcel Energy Inc.'s \$500 million 364-day term loan agreement entered into in December 2017.

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

Money Pool — Xcel Energy received FERC approval 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. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

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, 2017 and 2016, Xcel Energy Inc. had approximately 508 million shares and 507 million shares of common stock outstanding, respectively. In addition, Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of seven million shares of \$100 par value preferred stock. Xcel Energy Inc. had no shares of preferred stock outstanding on Dec. 31, 2017 and 2016.

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.

Financing Plans — Xcel Energy Inc. and its utility subsidiaries' 2018 debt financing plans reflect the following:

- Xcel Energy Inc. plans to issue approximately \$750 million of senior unsecured bonds;
- NSP-Minnesota plans to issue approximately \$300 million of first mortgage bonds;
- NPS-Wisconsin plans to issue approximately \$200 million of first mortgage bonds;
- PSCo plans to issue approximately \$750 million of first mortgage bonds; and
- SPS plans to issue approximately \$350 million of first mortgage bonds.

Xcel Energy also plans to issue approximately \$300 million of incremental equity in addition to \$385 million of equity to be issued through the DRIP and benefit programs during the five-year forecast time period.

Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions and other factors.

Long-Term Borrowings and Other Financing Instruments — See the consolidated statements of capitalization and a discussion of the long-term borrowings in Note 4 to the consolidated financial statements.

Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy's 2018 GAAP and ongoing earnings guidance is \$2.37 to \$2.47 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 be within a range of 0 percent to 0.5 percent over 2017 levels.
- Weather-normalized retail firm natural gas sales are projected to be within a range of 0 percent to 0.5 percent below 2017 levels.
- Capital rider revenue is projected to increase by \$30 million to \$40 million over 2017 levels. PTCs are flowed back to customers, primarily through capital riders and reductions to electric margin.
- O&M expenses are projected to be flat.
- Depreciation expense is projected to increase approximately \$150 million to \$160 million over 2017 levels. Approximately \$20 million of the increase in depreciation expense reflects an increased renewable development fund, which is recovered in revenue and will not have an impact on earnings.
- Property taxes are projected to increase approximately \$30 million to \$40 million over 2017 levels.
- Interest expense (net of AFUDC — debt) is projected to increase \$20 million to \$30 million over 2017 levels.
- AFUDC — equity is projected to increase approximately \$20 million to \$30 million from 2017 levels.
- The ETR is projected to be approximately 8 percent to 10 percent. The lower ETR for 2018 compared to 2017 reflects the lower tax rate as part of the TCJA, including excess deferred taxes and PTCs which are flowed back to customers through margin. The ETR would be approximately 21 percent to 23 percent excluding excess deferred taxes and PTCs.

^(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 diluted EPS to corresponding GAAP diluted EPS.

Long-Term EPS and Dividend Growth Rate Objectives

Long-Term EPS and Dividend Growth Rate Objectives — Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 5 percent to 6 percent off of a 2017 base of \$2.30 per share;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent; and
- Maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range.

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 18 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

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

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

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

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2017. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we believe that, as of Dec. 31, 2017, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

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

/s/ BEN FOWKE

Ben Fowke

Chairman, President and Chief Executive Officer

Feb. 23, 2018

/s/ ROBERT C. FRENZEL

Robert C. Frenzel

Executive Vice President, Chief Financial Officer

Feb. 23, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the “Company”) as of December 31, 2017, 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 Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 23, 2018, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company’s management is responsible 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 the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

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

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

	Year Ended Dec. 31		
	2017	2016	2015
Operating revenues			
Electric	\$ 9,676	\$ 9,500	\$ 9,276
Natural gas	1,650	1,531	1,672
Other	78	76	76
Total operating revenues	<u>11,404</u>	<u>11,107</u>	<u>11,024</u>
Operating expenses			
Electric fuel and purchased power	3,757	3,718	3,763
Cost of natural gas sold and transported	823	733	905
Cost of sales — other	34	36	36
Operating and maintenance expenses	2,303	2,326	2,330
Conservation and demand side management program expenses	273	245	225
Depreciation and amortization	1,479	1,303	1,124
Taxes (other than income taxes)	545	532	512
Loss on Monticello life cycle management/extended power uprate project.	—	—	129
Total operating expenses	<u>9,214</u>	<u>8,893</u>	<u>9,024</u>
Operating income	2,190	2,214	2,000
Other income, net	23	8	6
Equity earnings of unconsolidated subsidiaries	30	42	34
Allowance for funds used during construction — equity	75	60	56
Interest charges and financing costs			
Interest charges — includes other financing costs of \$24, \$25 and \$24, respectively	663	647	595
Allowance for funds used during construction — debt	(35)	(27)	(26)
Total interest charges and financing costs	<u>628</u>	<u>620</u>	<u>569</u>
Income before income taxes	1,690	1,704	1,527
Income taxes	542	581	543
Net income	<u>\$ 1,148</u>	<u>\$ 1,123</u>	<u>\$ 984</u>
Weighted average common shares outstanding:			
Basic	509	509	508
Diluted	509	509	508
Earnings per average common share:			
Basic	\$ 2.26	\$ 2.21	\$ 1.94
Diluted	2.25	2.21	1.94
Cash dividends declared per common share.	\$ 1.44	\$ 1.36	\$ 1.28

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2017	2016	2015
Net income	\$ 1,148	\$ 1,123	\$ 984
Other comprehensive income (loss)			
Pension and retiree medical benefits:			
Net pension and retiree medical losses arising during the period, net of tax of \$(2), \$(5), and \$(5), respectively	(3)	(8)	(8)
Amortization of losses included in net periodic benefit cost, net of tax of \$5, \$2, and \$2, respectively	7	4	3
	4	(4)	(5)
Derivative instruments:			
Reclassification of losses to net income, net of tax of \$2, \$2, and \$2, respectively. . . .	3	4	3
	7	—	(2)
Other comprehensive income (loss)	7	—	(2)
Comprehensive income	\$ 1,155	\$ 1,123	\$ 982

See Notes to Consolidated Financial Statements

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

	Year Ended Dec. 31		
	2017	2016	2015
Operating activities			
Net income	\$ 1,148	\$ 1,123	\$ 984
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,495	1,319	1,143
Conservation and demand side management program amortization	2	4	5
Nuclear fuel amortization	114	117	106
Deferred income taxes	640	587	536
Amortization of investment tax credits	(5)	(5)	(5)
Allowance for equity funds used during construction	(75)	(60)	(56)
Equity earnings of unconsolidated subsidiaries	(30)	(42)	(34)
Dividends from unconsolidated subsidiaries	41	46	40
Provision for bad debts	39	39	36
Share-based compensation expense	57	41	45
Loss on Monticello life cycle management/extended power uprate project	—	—	129
Net realized and unrealized hedging and derivative transactions	2	8	22
Other, net	(3)	(1)	(1)
Changes in operating assets and liabilities:			
Accounts receivable	(60)	(83)	66
Accrued unbilled revenues	(34)	(75)	74
Inventories	(3)	1	(11)
Other current assets	9	61	9
Accounts payable	43	118	(120)
Net regulatory assets and liabilities	(16)	(19)	102
Other current liabilities	(38)	20	78
Pension and other employee benefit obligations	(133)	(91)	(69)
Change in other noncurrent assets	(1)	(16)	11
Change in other noncurrent liabilities	(66)	(40)	(52)
Net cash provided by operating activities	<u>3,126</u>	<u>3,052</u>	<u>3,038</u>
Investing activities			
Utility capital/construction expenditures	(3,319)	(3,256)	(3,683)
Allowance for equity funds used during construction	75	61	56
Proceeds from insurance recoveries	—	5	27
Purchases of investment securities	(1,697)	(547)	(1,258)
Proceeds from the sale of investment securities	1,669	479	1,237
Investments in unconsolidated subsidiaries and other	(17)	(4)	(2)
Other, net	(7)	1	—
Net cash used in investing activities	<u>(3,296)</u>	<u>(3,261)</u>	<u>(3,623)</u>
Financing activities			
Proceeds from (repayments of) short-term borrowings, net	422	(454)	(174)
Proceeds from issuance of long-term debt	1,518	2,424	1,626
Repayments of long-term debt, including reacquisition premiums	(1,030)	(1,036)	(251)
Proceeds from issuance of common stock	—	—	7
Repurchases of common stock	(3)	(32)	—
Dividends paid	(721)	(681)	(607)
Other	(18)	(12)	(11)
Net cash provided by financing activities	<u>168</u>	<u>209</u>	<u>590</u>
Net change in cash and cash equivalents	(2)	—	5
Cash and cash equivalents at beginning of period	85	85	80
Cash and cash equivalents at end of period	<u>\$ 83</u>	<u>\$ 85</u>	<u>\$ 85</u>
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	\$ (616)	\$ (592)	\$ (543)
Cash received for income taxes, net	44	62	58
Supplemental disclosure of non-cash investing and financing transactions:			
Property, plant and equipment additions in accounts payable	\$ 415	\$ 254	\$ 322
Issuance of common stock for reinvested dividends and equity awards	31	29	53

See Notes to Consolidated Financial Statements

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

	Dec. 31	
	2017	2016
Assets		
Current assets		
Cash and cash equivalents	\$ 83	\$ 85
Accounts receivable, net	797	776
Accrued unbilled revenues	764	730
Inventories	610	604
Regulatory assets	424	364
Derivative instruments	44	38
Prepaid taxes	68	107
Prepayments and other	183	138
Total current assets	<u>2,973</u>	<u>2,842</u>
Property, plant and equipment, net	34,329	32,842
Other assets		
Nuclear decommissioning fund and other investments	2,397	2,092
Regulatory assets	3,005	3,081
Derivative instruments	48	50
Deposits and other	278	248
Total other assets	<u>5,728</u>	<u>5,471</u>
Total assets	<u>\$ 43,030</u>	<u>\$ 41,155</u>
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	\$ 457	\$ 255
Short-term debt	814	392
Accounts payable	1,243	1,045
Regulatory liabilities	239	221
Taxes accrued	448	457
Accrued interest	174	173
Dividends payable	183	172
Derivative instruments	29	27
Other	501	505
Total current liabilities	<u>4,088</u>	<u>3,247</u>
Deferred credits and other liabilities		
Deferred income taxes	3,845	6,784
Deferred investment tax credits	58	63
Regulatory liabilities	5,083	1,383
Asset retirement obligations	2,475	2,782
Derivative instruments	126	148
Customer advances	193	195
Pension and employee benefit obligations	1,042	1,112
Other	145	225
Total deferred credits and other liabilities	<u>12,967</u>	<u>12,692</u>
Commitments and contingencies		
Capitalization		
Long-term debt	14,520	14,195
Common stock — 1,000,000,000 shares authorized of \$2.50 par value; 507,762,881 and 507,222,795 shares outstanding at Dec. 31, 2017 and 2016, respectively	1,269	1,268
Additional paid in capital	5,898	5,881
Retained earnings	4,413	3,982
Accumulated other comprehensive loss	(125)	(110)
Total common stockholders' equity	<u>11,455</u>	<u>11,021</u>
Total liabilities and equity	<u>\$ 43,030</u>	<u>\$ 41,155</u>

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			Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value	Additional Paid In Capital			
Balance at Dec. 31, 2014	505,733	\$ 1,264	\$ 5,837	\$ 3,221	\$ (108)	\$ 10,214
Net income				984		984
Other comprehensive loss.....					(2)	(2)
Dividends declared on common stock				(652)		(652)
Issuances of common stock	1,803	5	28			33
Share-based compensation			24			24
Balance at Dec. 31, 2015	<u>507,536</u>	<u>\$ 1,269</u>	<u>\$ 5,889</u>	<u>\$ 3,553</u>	<u>\$ (110)</u>	<u>\$ 10,601</u>
Net income				1,123		1,123
Dividends declared on common stock				(694)		(694)
Issuances of common stock	486	1	15			16
Repurchases of common stock	(799)	(2)	(30)			(32)
Share-based compensation			7			7
Balance at Dec. 31, 2016	<u>507,223</u>	<u>\$ 1,268</u>	<u>\$ 5,881</u>	<u>\$ 3,982</u>	<u>\$ (110)</u>	<u>\$ 11,021</u>
Net income				1,148		1,148
Other comprehensive income					7	7
Dividends declared on common stock				(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	<u>507,763</u>	<u>\$ 1,269</u>	<u>\$ 5,898</u>	<u>\$ 4,413</u>	<u>\$ (125)</u>	<u>\$ 11,455</u>

See Notes to Consolidated Financial Statements

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

	Dec. 31	
	2017	2016
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
March 1, 2018, 5.25%	\$ —	\$ 500
Aug. 15, 2020, 2.2%	300	300
Aug. 15, 2022, 2.15%	300	300
May 15, 2023, 2.6%	400	400
July 1, 2025, 7.125%	250	250
March 1, 2028, 6.5%	150	150
July 15, 2035, 5.25%	250	250
June 1, 2036, 6.25%	400	400
July 1, 2037, 6.2%	350	350
Nov. 1, 2039, 5.35%	300	300
Aug. 15, 2040, 4.85%	250	250
Aug. 15, 2042, 3.4%	500	500
May 15, 2044, 4.125%	300	300
Aug. 15, 2045, 4.0%	300	300
May 15, 2046, 3.6%	350	350
Sept. 15, 2047, 3.6%	600	—
Unamortized discount	(22)	(17)
Unamortized debt expense	(45)	(40)
Total NSP-Minnesota long-term debt	\$ 4,933	\$ 4,843
PSCo		
First Mortgage Bonds, Series due:		
Aug. 1, 2018, 5.8%	\$ 300	\$ 300
June 1, 2019, 5.125%	400	400
Nov. 15, 2020, 3.2%	400	400
Sept. 15, 2022, 2.25%	300	300
March 15, 2023, 2.5%	250	250
May 15, 2025, 2.9%	250	250
Sept. 1, 2037, 6.25%	350	350
Aug. 1, 2038, 6.5%	300	300
Aug. 15, 2041, 4.75%	250	250
Sept. 15, 2042, 3.6%	500	500
March 15, 2043, 3.95%	250	250
March 15, 2044, 4.30%	300	300
June 15, 2046, 3.55%	250	250
June 15, 2047, 3.8%	400	—
Capital lease obligations, through 2060, 11.2% — 14.3%	151	156
Unamortized discount	(13)	(13)
Unamortized debt expense	(29)	(27)
Total	4,609	4,216
Less current maturities	306	5
Total PSCo long-term debt	\$ 4,303	\$ 4,211
SPS		
First Mortgage Bonds, Series due:		
June 15, 2024, 3.3%	\$ 350	\$ 350
Aug. 15, 2041, 4.5%	400	400
Aug. 15, 2046, 3.4%	300	300
Aug. 15, 2047, 3.7%	450	—
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	—	250
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100	100
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250	250
Unamortized discount	(2)	—
Unamortized debt expense	(18)	(14)
Total SPS long-term debt	\$ 1,830	\$ 1,636

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION — (Continued)
(amounts in millions, except share and per share data)

	Dec. 31	
	2017	2016
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	\$ 150	\$ 150
June 15, 2024, 3.3%	200	200
Sept. 1, 2038, 6.375%	200	200
Oct. 1, 2042, 3.7%	100	100
Dec. 1, 2047, 3.75%	100	—
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6% ^(a)	19	19
Other	2	2
Unamortized discount	(3)	(3)
Unamortized debt expense	(7)	(5)
Total	761	663
Less current maturities	151	1
Total NSP-Wisconsin long-term debt	\$ 610	\$ 662
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2018-2052, 0% — 7.05%	\$ 28	\$ 31
Less current maturities	2	1
Total other subsidiaries long-term debt	\$ 26	\$ 30
Xcel Energy Inc.		
Unsecured Senior Notes, Series due:		
June 1, 2017, 1.2%	\$ —	\$ 250
May 15, 2020, 4.7%	550	550
March 15, 2021, 2.4%	400	400
March 15, 2022, 2.6%	300	300
June 1, 2025, 3.3%	600	600
Dec. 1, 2026, 3.35%	500	500
July 1, 2036, 6.5%	300	300
Sept. 15, 2041, 4.8%	250	250
Elimination of PSCo capital lease obligation with affiliates	(62)	(64)
Unamortized discount	(2)	(2)
Unamortized debt expense	(20)	(23)
Total	2,816	3,061
Less current maturities (including elimination of PSCo capital lease obligation)	(2)	248
Total Xcel Energy Inc. long-term debt	2,818	2,813
Total long-term debt	\$ 14,520	\$ 14,195
Common Stockholders' Equity		
Common stock — 1,000,000,000 shares authorized of \$2.50 par value; 507,762,881 and 507,222,795 shares outstanding at Dec. 31, 2017 and 2016, respectively	\$ 1,269	\$ 1,268
Additional paid in capital	5,898	5,881
Retained earnings	4,413	3,982
Accumulated other comprehensive loss	(125)	(110)
Total common stockholders' equity	\$ 11,455	\$ 11,021

^(a) Resource recovery financing.

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts — 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 consolidated financial statements and disclosures are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation — In 2017, Xcel Energy's operations included the activity 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 Xcel Energy's operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipelines, storage and compression facilities.

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

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. In the consolidation process, all intercompany transactions and balances are eliminated. 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 several plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 5 for further discussion of jointly owned generation, transmission and gas facilities, and related ownership percentages.

Xcel Energy evaluates its arrangements and contracts with other entities, including investments, PPAs and fuel contracts, to determine if the other party is a VIE, if Xcel Energy has a variable interest and if Xcel Energy is the primary beneficiary. Xcel Energy follows accounting guidance for VIEs which requires consideration of the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether Xcel Energy is a VIE's primary beneficiary. See Note 13 for further discussion of VIEs.

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

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

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

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

If restructuring or other changes in the regulatory environment occur, regulated 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 financial condition, results of operations and cash flows. See Note 15 for further discussion of regulatory assets and liabilities.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. Xcel Energy's utility subsidiaries recognize sales to both native load and other end use customers on a gross basis. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis in electric revenues and cost of sales. Other revenues and charges related to participating and transacting in RTOs are recorded on a net basis in cost of sales.

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

Certain rate rider mechanisms qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

Conservation Programs — Xcel Energy Inc.'s utility subsidiaries have implemented programs in many of their retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas systems. These programs include efficiency and redesign programs, as well as rebates for the purchase of items such as high efficiency lighting.

The costs incurred for DSM and CIP programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of 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.

For PSCo, SPS and NSP-Minnesota, DSM and CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage Xcel Energy's achievement of energy conservation goals and compensate for related lost sales margin. For these utility subsidiaries, regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers. NSP-Wisconsin recovers approved conservation program costs in base rate revenue.

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

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. See Note 12 for a discussion of the loss recognized in 2015 related to the Monticello LCM/EPU project. 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 related to its plant using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.1, 2.9, and 2.8 percent for the years ended Dec. 31, 2017, 2016 and 2015, respectively.

Leases — Xcel Energy evaluates a variety of contracts for lease classification at inception, including PPAs and rental arrangements for office space, vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 13 for further discussion of leases.

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

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

AROs — Xcel Energy Inc.'s utility subsidiaries account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 13 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota's most recent triennial nuclear decommissioning studies were filed with the MPUC in December 2017. These studies reflect NSP-Minnesota's plans for dismantlement of the Monticello and PI facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a U.S. government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. 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. See Note 14 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

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 11 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC) and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling O&M costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

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

The effects of tax rate changes that are attributable to the regulated 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. 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, the reversal of some temporary differences are accounted for as current income tax expense. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 15.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

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.

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

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

See Note 6 for further discussion of income taxes.

Types of and Accounting for 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. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the consolidated balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 11.

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

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

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

See Note 11 for further discussion of Xcel Energy's risk management and derivative activities.

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

Xcel Energy's commodity trading operations are primarily conducted by NSP-Minnesota and PSCo. 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 11 for further discussion.

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 as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, 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 the 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 9 and 11 for further discussion.

Cash and Cash Equivalents — Xcel Energy considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

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

Inventory — All inventory is recorded at average cost.

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

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

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

Emission Allowances — Emission allowances, including the annual SO₂ and NO_x emission allowance entitlement received from the EPA, are recorded at cost plus associated broker commission fees. Xcel Energy follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenue and the operating activities section of the consolidated statements of cash flows.

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, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

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

See Note 13 for further discussion of environmental costs.

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 under applicable accounting guidance requires management to make various assumptions and estimates.

Based on the regulatory recovery mechanisms of Xcel Energy Inc.'s utility subsidiaries, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 9 for further discussion of benefit plans and other postretirement benefits.

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

The obligation recognized is reduced over the term of the guarantee as Xcel Energy is released from risk under the guarantee. See Note 13 for specific details of issued guarantees.

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

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the FASB issued *Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09)*, which provides a new framework for the recognition of revenue. As the appropriate timing of recognition of revenue from contracts with customers in our regulated operations continues to generally be based on the delivery of electricity and natural gas, Xcel Energy's adoption will primarily result in increased disclosures regarding sources of revenues, including alternative revenue programs. The guidance is effective for interim and annual periods beginning after Dec. 15, 2017. Xcel Energy is implementing the standard on a modified retrospective basis, which requires application to contracts with customers effective Jan. 1, 2018.

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

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

Presentation of Net Periodic Benefit Cost — In March 2017, the FASB issued *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715 (ASU No. 2017-07)*, which establishes that only the service cost element of pension cost may be presented as a component of operating income in the income statement. Also under the guidance, only the service cost component of pension cost is eligible for capitalization. As a result of application of accounting principles for rate regulated entities, a similar amount of pension cost, including non-service components, will be recognized consistent with the historical ratemaking treatment and the impacts of adoption will be limited to changes in classification of non-service costs in the consolidated statement of income. This guidance is effective for interim and annual reporting periods beginning after Dec. 15, 2017.

Recently Adopted

Stock Compensation — In March 2016, the FASB issued *Improvements to Employee Share-Based Payment Accounting, Topic 718 (ASU No. 2016-09)*, which simplifies accounting and financial statement presentation for share-based payment transactions. The guidance requires that the difference between the tax deduction available upon settlement of share-based equity awards and the tax benefit accumulated over the vesting period be recognized as an adjustment to income tax expense. Xcel Energy adopted the guidance in 2016, resulting in immaterial 2016 adjustments to income tax expense and changes in classification of cash flows related to tax withholding in the consolidated statements of cash flows for 2016 and prior presented periods.

Accounting for the TCJA — In December 2017, the SEC staff issued Staff Accounting Bulletin No. 118 *Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118)*, to supplement the accounting requirements of ASC Topic 740 *Income Taxes (ASC Topic 740)* as it relates to assessing and recognizing the impacts of the TCJA in the period of enactment. SAB 118 allows an entity to recognize provisional amounts in its financial statements in circumstances in which the entity's assessment is incomplete, but for which a reasonable estimate can be made. Provisional amounts recognized are subject to adjustment for up to one year from the enactment date. For further details, see Note 6 to the consolidated financial statements.

Reporting Comprehensive Income — In February 2018, the FASB issued *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, Topic 220 (ASU No. 2018-02)*, which addresses the stranded amounts of accumulated OCI which may result from enactment of a new tax law. Though accumulated OCI is presented on a net-of-tax basis, ASC Topic 740 requires that the effects of new tax laws on items in accumulated OCI be recognized without a corresponding adjustment to accumulated OCI, and instead recorded to income tax expense. ASU No. 2018-02 permits stranded amounts of accumulated OCI specifically resulting from the TCJA to be removed from accumulated OCI and reclassified to retained earnings, if elected. Xcel Energy adopted the guidance in the fourth quarter of 2017, and elected to recognize a \$22 million increase to accumulated other comprehensive loss and retained earnings in the consolidated financial statements for the year ended Dec. 31, 2017, related to a revaluation of deferred income tax assets and liabilities for items in accumulated other comprehensive loss, at the TCJA federal tax rate.

3. Selected Balance Sheet Data

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Accounts receivable, net		
Accounts receivable	\$ 849	\$ 827
Less allowance for bad debts	(52)	(51)
	<u>\$ 797</u>	<u>\$ 776</u>
(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Inventories		
Materials and supplies	\$ 311	\$ 312
Fuel	186	182
Natural gas	113	110
	<u>\$ 610</u>	<u>\$ 604</u>

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Property, plant and equipment, net		
Electric plant	\$ 39,016	\$ 38,221
Natural gas plant	5,800	5,318
Common and other property	2,013	1,888
Plant to be retired ^(a)	11	32
CWIP	2,087	1,373
Total property, plant and equipment	48,927	46,832
Less accumulated depreciation	(15,000)	(14,381)
Nuclear fuel	2,697	2,572
Less accumulated amortization	(2,295)	(2,181)
	<u>\$ 34,329</u>	<u>\$ 32,842</u>

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

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. 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. The money pool balances are eliminated in consolidation.

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

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2017		
Borrowing limit	\$		3,250
Amount outstanding at period end			814
Average amount outstanding			560
Maximum amount outstanding			814
Weighted average interest rate, computed on a daily basis			1.63%
Weighted average interest rate at period end			1.90

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31		
	2017	2016	2015
Borrowing limit	\$ 3,250	\$ 2,750	\$ 2,750
Amount outstanding at period end	814	392	846
Average amount outstanding	644	485	601
Maximum amount outstanding	1,247	1,183	1,360
Weighted average interest rate, computed on a daily basis	1.35%	0.74%	0.48%
Weighted average interest rate at end of period	1.90	0.95	0.82

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2017 and 2016, there were \$30 million and \$19 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities — In order to use their 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.

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

Other features of the credit facilities include:

- Xcel Energy Inc. may increase its credit facility by up to \$200 million, NSP-Minnesota and PSCo may each increase their credit facilities by \$100 million and SPS may increase its credit facility by \$50 million. The NSP-Wisconsin credit facility cannot be increased.
- Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance as of Dec. 31, 2017 and 2016, respectively, as evidenced by the table below:

	Debt-to-Total Capitalization Ratio	
	2017	2016
Xcel Energy Inc.	58%	57%
NSP-Wisconsin	47	47
NSP-Minnesota	48	48
SPS.	46	47
PSCo	44	45

- If Xcel Energy Inc. or any of 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.
- The Xcel Energy Inc. credit facility has a cross-default provision that provides 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 percent of Xcel Energy's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding \$75 million.
- Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants in their debt agreements as of Dec. 31, 2017 and 2016.

Xcel Energy Inc. entered into a 364-day term loan agreement on Dec. 5, 2017 to borrow up to \$500 million. As of Dec. 31, 2017, Xcel Energy Inc. had borrowed \$250 million of the Term Loan. Xcel Energy Inc. may recommit for one additional 364-day period from the December 2018 maturity date, subject to majority consent from lenders.

As of Dec. 31, 2017, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility ^(a)	Drawn ^(b)	Available
Xcel Energy Inc.	\$ 1,500	\$ 783	\$ 717
PSCo.	700	3	697
NSP-Minnesota.	500	44	456
SPS.	400	2	398
NSP-Wisconsin.	150	11	139
Total.	<u>\$ 3,250</u>	<u>\$ 843</u>	<u>\$ 2,407</u>

^(a) These credit facilities mature in June 2021, with the exception of Xcel Energy Inc.'s \$500 million 364-day term loan agreement entered into in December 2017.

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

All credit facility bank borrowings, outstanding letters of credit, term loan borrowings and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding as of Dec. 31, 2017 and 2016.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal 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 associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Maturities of long-term debt are as follows:

<u>(Millions of Dollars)</u>	
2018	\$ 457
2019	405
2020	1,256
2021	425
2022	905

During 2017, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- PSCo issued \$400 million of 3.80 percent first mortgage bonds due June 15, 2047;
- SPS issued \$450 million of 3.70 percent first mortgage bonds due Aug. 15, 2047;
- NSP-Minnesota issued \$600 million of 3.60 percent first mortgage bonds due Sept. 15, 2017;
- NSP-Wisconsin issued \$100 million of 3.75 percent first mortgage bonds due Dec. 1, 2047; and
- Xcel Energy Inc. entered into a \$500 million 364-Day Term Loan Agreement.

During 2016, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- Xcel Energy Inc. issued \$400 million of 2.40 percent senior notes due March 15, 2021 and \$350 million of 3.30 percent senior notes due June 1, 2025;
- NSP-Minnesota issued \$350 million of 3.60 percent first mortgage bonds due May 15, 2046;
- PSCo issued \$250 million of 3.55 percent first mortgage bonds due June 15, 2046;
- SPS issued \$300 million of 3.40 percent first mortgage bonds due Aug. 15, 2046; and
- Xcel Energy Inc. issued \$300 million of 2.60 percent senior notes due March 15, 2022 and \$500 million of 3.35 percent senior notes due Dec. 1, 2026.

Deferred Financing Costs — Deferred financing costs of approximately \$119 million and \$109 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2017 and 2016, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — Xcel Energy Inc. has 7,000,000 shares of preferred stock authorized to be issued with a \$100 par value. As of Dec. 31, 2017 and 2016, there were no shares of preferred stock outstanding.

The charters of PSCo and SPS authorize each subsidiary to issue 10,000,000 shares of preferred stock with par values of \$0.01 and \$1.00 per share, respectively. As of Dec. 31, 2017 and 2016, there were no preferred shares of subsidiaries outstanding.

Xcel Energy Inc. has 1 billion shares of common stock authorized to be issued with a \$2.50 par value. Outstanding shares as of Dec. 31, 2017 and 2016 were 507,762,881 and 507,222,795, respectively.

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its subsidiaries to pay dividends. All of Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only. Due to certain restrictive covenants, Xcel Energy Inc. is required to be current on particular interest payments before dividends can be paid.

The most restrictive dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS are imposed by their respective state regulatory commission. PSCo's dividends are subject to the FERC's jurisdiction.

Only NSP-Minnesota has a first mortgage indenture which places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.9 billion and \$1.7 billion in additional cash dividends to Xcel Energy Inc. as of Dec. 31, 2017 and 2016, respectively.

NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay by requiring an equity-to-total capitalization ratio between 47.2 percent and 57.6 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2017 and \$1.1 billion in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$10.4 billion at Dec. 31, 2017, which did not exceed the limit of \$11.2 billion.

NSP-Wisconsin cannot pay annual dividends in excess of approximately \$53 million if its calendar year average equity-to-total capitalization ratio is or falls below the state commission authorized level as calculated by PSCW requirements. NSP-Wisconsin's calendar year average equity ratio calculated on this basis was 53.1 percent as of Dec. 31, 2017 and \$19 million in retained earnings was not restricted. NSP-Wisconsin's authorized equity ratio was 52.5 percent for 2016 and 2017, but will be 51.5 percent for 2018.

SPS' state regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc. by requiring an equity-to-total capitalization ratio (excluding short-term debt) between 45.0 percent and 55.0 percent. In addition, SPS may not pay a dividend that would cause it to lose its investment grade bond rating. SPS' equity ratio (excluding short-term debt) was 53.8 percent as of Dec. 31, 2017 and \$542 million in retained earnings was not restricted.

The issuance of securities by Xcel Energy Inc. generally is not subject to regulatory approval. However, utility financings and certain intra-system financings are subject to the jurisdiction of the applicable state regulatory commissions and/or the FERC. As of Dec. 31, 2017:

- PSCo has authorization to issue up to an additional \$1.8 billion of long-term debt and up to \$800 million of short-term debt.
- SPS has authorization to issue up to \$500 million of short-term debt and SPS will file for additional long-term debt authorization.
- NSP-Wisconsin has authorization to issue an additional \$250 million of long-term debt and up to \$150 million of short-term debt.
- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 47.2 percent and 57.6 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed \$11.2 billion.

Xcel Energy believes these authorizations are adequate and seeks additional authorization as necessary.

5. Joint Ownership of Generation, Transmission and Gas Facilities

Following are the investments by Xcel Energy Inc.'s utility subsidiaries in jointly owned generation, transmission and gas facilities and the related ownership percentages as of Dec. 31, 2017:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Minnesota				
Electric Generation:				
Sherco Unit 3	\$ 612	\$ 411	\$ 1	59%
Sherco Common Facilities Units 1, 2 and 3	145	99	1	80
Sherco Substation.	5	3	—	59
Electric Transmission:				
Grand Meadow Line and Substation	11	2	—	50
CapX2020 Transmission	1,039	138	2	51
Total NSP-Minnesota	<u>\$ 1,812</u>	<u>\$ 653</u>	<u>\$ 4</u>	
(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
NSP-Wisconsin				
Electric Transmission:				
CapX2020 Transmission	\$ 162	\$ 12	\$ 103	81%
La Crosse, Wis. to Madison, Wis.	—	—	102	37
Total NSP-Wisconsin	<u>\$ 162</u>	<u>\$ 12</u>	<u>\$ 205</u>	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Ownership %
PSCo				
Electric Generation:				
Hayden Unit 1	\$ 150	\$ 72	\$ 1	76%
Hayden Unit 2	149	65	—	37
Hayden Common Facilities	39	20	—	53
Craig Units 1 and 2	81	39	—	10
Craig Common Facilities 1, 2 and 3	39	20	—	7
Comanche Unit 3	890	118	—	67
Comanche Common Facilities	24	2	3	82
Electric Transmission:				
Transmission and other facilities, including substations	177	67	1	Various
Gas Transportation:				
Rifle, Colo. to Avon, Colo.	22	8	—	60
Gas Transportation Compressor	8	1	—	50
Total PSCo	<u>\$ 1,579</u>	<u>\$ 412</u>	<u>\$ 5</u>	

NSP-Minnesota and PSCo have approximately 517 MW and 816 MW of jointly owned generating capacity, respectively. Each Company's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

6. Income Taxes

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

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

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

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

The fourth quarter 2017 estimated accounting impacts of the December 2017 enactment of the new tax law at Xcel Energy 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 percent 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 has accounted for the state tax impacts of federal tax reform based on currently enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

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

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

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

- Recognition of additional tax deductions for bonus depreciation of \$1.2 billion, and as a result, recognition of \$5 million benefit related to a carryback claim (see additional discussion below) and \$4 million expense related to valuation allowances and expirations of charitable contribution carryforwards; and
- Recognition of \$7 million benefit for federal R&E credits.

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

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy’s federal income tax returns expire as follows:

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

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims that would have resulted in \$14 million of income tax expense for the 2009 through 2011 claims, and the 2013 through 2015 claims. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (“Appeals”). In the third quarter of 2017, Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. As of Dec. 31, 2017, the case has been forwarded to the Joint Committee on Taxation.

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

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Dec. 31, 2017, Xcel Energy’s earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado.....	2009
Minnesota.....	2009
Texas.....	2009
Wisconsin.....	2012

In 2016, Minnesota began an audit of years 2010 through 2014. As of Dec. 31, 2017, Minnesota had not proposed any material adjustments.

In 2016, Texas began an audit of years 2009 and 2010, and in September 2017, began an audit of year 2011. In the fourth quarter of 2017, Texas concluded these audits and Xcel Energy recognized the related benefit.

In 2016, Wisconsin began an audit of years 2012 and 2013. As of Dec. 31, 2017, Wisconsin had not proposed any material adjustments.

As of Dec. 31, 2017, there were no other state income tax audits in progress.

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

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Unrecognized tax benefit — Permanent tax positions	\$ 20	\$ 30
Unrecognized tax benefit — Temporary tax positions	19	104
Total unrecognized tax benefit	<u>\$ 39</u>	<u>\$ 134</u>

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

(Millions of Dollars)	2017	2016	2015
Balance at Jan. 1	\$ 134	\$ 121	\$ 67
Additions based on tax positions related to the current year	6	8	27
Reductions based on tax positions related to the current year	(4)	—	(5)
Additions for tax positions of prior years	15	10	35
Reductions for tax positions of prior years	(105)	(5)	(3)
Settlements with taxing authorities	(7)	—	—
Balance at Dec. 31	<u>\$ 39</u>	<u>\$ 134</u>	<u>\$ 121</u>

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
NOL and tax credit carryforwards.....	\$ (31)	\$ (44)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audits resume, the Minnesota and Wisconsin audits progress, and other state audits resume. As the IRS Appeals, Minnesota and Wisconsin audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$15 million.

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

(Millions of Dollars)	2017	2016
Payable for interest related to unrecognized tax benefits at Jan. 1	\$ (3)	\$ —
Interest income (expense) income related to unrecognized tax benefits	3	(3)
Payable for interest related to unrecognized tax benefits at Dec. 31	<u>\$ —</u>	<u>\$ (3)</u>

The payable for interest related to unrecognized tax benefits was immaterial for 2015.

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

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

(Millions of Dollars)	2017	2016
Federal NOL carryforward	\$ 1,072	\$ 1,916
Federal tax credit carryforwards	517	424
Valuation allowances for federal credit carryforwards	(5)	—
State NOL carryforwards	1,592	1,949
Valuation allowances for state NOL carryforwards	(55)	(59)
State tax credit carryforwards, net of federal detriment ^(a)	90	74
Valuation allowances for state credit carryforwards, net of federal benefit ^(b)	(68)	(54)

^(a) State tax credit carryforwards are net of federal detriment of \$24 million and \$40 million as of Dec. 31, 2017 and 2016, respectively.

^(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of \$18 million and \$29 million as of Dec. 31, 2017 and 2016, respectively.

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

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2017	2016 ^(b)	2015 ^(b)
Federal statutory rate	35.0%	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	3.9%	3.9%	3.9%
Increases (decreases) in tax from:			
Wind production tax credits recognized	(4.7)	(3.4)	(1.8)
Other tax credits recognized, net of federal income tax expense	(1.0)	(0.8)	(0.9)
Tax reform	1.4	—	—
Regulatory differences - effects of rate changes ^(a)	(0.1)	(0.1)	(0.1)
Regulatory differences - other utility plant items	(0.7)	(0.5)	(0.9)
Change in unrecognized tax benefits	(0.6)	0.2	0.6
NOL carryback	—	—	(0.3)
Other, net	(1.1)	(0.2)	—
Effective income tax rate	<u>32.1%</u>	<u>34.1%</u>	<u>35.5%</u>

^(a) The amortization of excess deferred taxes.

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

The components of Xcel Energy's income tax expense for the years ending Dec. 31 were:

(Millions of Dollars)	2017	2016	2015
Current federal tax expense (benefit)	\$ 1	\$ (3)	\$ (36)
Current state tax (benefit) expense	(11)	(4)	2
Current change in unrecognized tax (benefit) expense	(83)	6	46
Deferred federal tax expense	460	477	480
Deferred state tax expense	107	112	92
Deferred change in unrecognized tax expense (benefit)	73	(2)	(36)
Deferred investment tax credits	(5)	(5)	(5)
Total income tax expense	<u>\$ 542</u>	<u>\$ 581</u>	<u>\$ 543</u>

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

(Millions of Dollars)	2017	2016	2015
Deferred tax (benefit) expense excluding items below	\$ (2,939)	\$ 631	\$ 547
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	3,583	(45)	(12)
Tax (expense) benefit allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(4)	1	1
Deferred tax expense	<u>\$ 640</u>	<u>\$ 587</u>	<u>\$ 536</u>

The components of Xcel Energy's net deferred tax liability at Dec. 31 were as follows:

(Millions of Dollars)	2017	2016 ^(a)
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 4,989	\$ 7,697
Regulatory assets	565	152
Pension expense	199	298
Other	69	89
Total deferred tax liabilities	<u>\$ 5,822</u>	<u>\$ 8,236</u>
Deferred tax assets:		
Regulatory liabilities	\$ 886	\$ (132)
Tax credit carryforward	607	498
NOL carryforward	293	754
NOL and tax credit valuation allowances	(77)	(57)
Other employee benefits	132	205
Deferred investment tax credits	17	27
Deferred fuel costs	12	11
Rate refund	10	33
Other	97	113
Total deferred tax assets	<u>\$ 1,977</u>	<u>\$ 1,452</u>
Net deferred tax liability	<u>\$ 3,845</u>	<u>\$ 6,784</u>

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

7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s 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 Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements. Common stock equivalents causing a dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards. Effective August 2015, 401(k) matching contributions are settled in cash for all Xcel Energy employee groups.

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

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

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

The dilutive impact of common stock equivalents affecting EPS was as follows:

(Amounts in millions, except per share data)	2017			2016			2015		
	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	\$ 1,148			\$ 1,123			\$ 984		
Basic EPS:									
Earnings available to common shareholders	1,148	508.5	\$ 2.26	1,123	508.8	\$ 2.21	984	507.8	\$ 1.94
Effect of dilutive securities:									
Equity awards	—	0.6		—	0.7		—	0.4	
Diluted EPS:									
Earnings available to common shareholders	\$ 1,148	509.1	\$ 2.25	\$ 1,123	509.5	\$ 2.21	\$ 984	508.2	\$ 1.94

Dividend Reinvestment and Stock Purchase Plan and Stock Compensation Settlements — In 2015, the Xcel Energy Inc. Board of Directors authorized open market purchases by the plan administrator as the source of shares for the dividend reinvestment program as well as market purchases of up to 3.0 million shares for stock compensation plan settlements. In 2017, Xcel Energy Inc. repurchased approximately 0.1 million shares of common stock in the open market at a total cost of approximately \$3 million.

8. Share-Based Compensation

Restricted Stock — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan and the 2015 Omnibus Incentive Plan (effective May 20, 2015). Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Xcel Energy Inc. reinvests dividends on the restricted stock while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.'s stock at the grant date.

Xcel Energy Inc. granted shares of restricted stock for the years ended Dec. 31 as follows:

(Shares in Thousands)	2017	2016	2015
Granted shares	15	20	42
Grant date fair value	\$ 42.00	\$ 38.82	\$ 35.00

A summary of the changes of nonvested restricted stock for the year ended 2017 were as follows:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2017	67	\$ 35.43
Granted	15	42.00
Forfeited	—	—
Vested	(40)	33.36
Dividend equivalents	2	44.69
Nonvested restricted stock at Dec. 31, 2017	44	39.71

Other Equity Awards — Xcel Energy Inc.'s Board of Directors has granted equity awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated in 2010) and the 2015 Omnibus Incentive Plan (effective May 20, 2015). These plans allow the attachment of various vesting conditions and performance goals to the awards granted. The vesting conditions and performance goals may vary by plan year. At the end of the restricted period, such grants will be awarded if the vesting conditions and/or performance goals are met.

Commencing in 2014, certain employees were granted equity awards with one portion of shares subject only to service conditions, and the other portion subject to performance conditions. Inclusive of other grants of time-based awards, a total of 0.3 million time-based equity shares subject only to service conditions were granted annually in 2017, 2016, and 2015, respectively. Other than shares associated with these time-based awards and restricted stock, payout of all other employee equity awards and the lapsing of restrictions on the transfer of units are based on the achievement of performance criteria.

The performance conditions for a portion of the awards granted from 2015 to 2017 are based on relative TSR, measured identically to TSR liability awards granted in those years, and measurement of performance for a portion of units awarded from 2011 to 2013 is based on EPS growth with an additional condition that Xcel Energy Inc.'s annual dividend paid on its common stock remains at a specified amount per share or greater. The performance conditions for the remaining employee equity awards are based on environmental goals. Equity awards with performance conditions awarded from 2011 to 2017, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years, with potential payouts ranging from zero to 150 percent for 2011 to 2013 grants, and zero to 200 percent for 2014 to 2017 grants, depending on the level of achievement.

- The 2012 awards measured on EPS growth and the 2012 environmental awards met their targets as of Dec. 31, 2014, and were settled in shares in February 2015.
- The 2013 awards measured on EPS growth, the 2013 environmental awards and the 2013 time-based awards met their targets as of Dec. 31, 2015, and were settled in shares in February 2016.
- The 2014 environmental awards and the 2014 time-based awards met their targets as of Dec. 31, 2016, and were settled in shares in February 2017.
- The 2015 environmental awards and the 2015 time-based awards met their targets as of Dec. 31, 2017, and will be settled in shares in February 2018.

Equity award units granted to employees, excluding restricted stock, for the years ended Dec. 31 were as follows:

(Units in Thousands)	2017	2016	2015
Granted units	503	522	496
Weighted average grant date fair value	\$ 41.02	\$ 36.00	\$ 36.09

Approximately 0.5 million of these units vested during 2017 at a total fair value of \$22 million. Approximately 0.5 million of these units vested during 2016 at a total fair value of \$22 million. Approximately 0.8 million of these units vested during 2015 at a total fair value of \$27 million.

A summary of the changes in the nonvested portion of these equity award units for the year ended 2017, were as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2017	984	\$ 36.05
Granted	503	41.02
Forfeited	(70)	37.12
Vested	(467)	36.17
Dividend equivalents	45	37.20
Nonvested Units at Dec. 31, 2017	995	38.48

The total fair value of these nonvested equity awards as of Dec. 31, 2017 was \$48 million and the weighted average remaining contractual life was 1.7 years.

Stock Equivalent Units — Non-employee members of the Xcel Energy Inc. Board of Directors receive annual awards of stock equivalent units, with each unit having a value equal to one share of Xcel Energy Inc. common stock. The annual grants are vested as of the date of each member's election to the Board of Directors; there is no further service or other condition attached to the annual grants. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash. Dividends on Xcel Energy Inc.'s common stock are converted to stock equivalent units and granted based on the number of stock equivalent units held by each participant as of the dividend date. The stock equivalent units are payable as a distribution of Xcel Energy Inc.'s common stock upon a director's termination of service.

The stock equivalent units granted for the years ended Dec. 31 were as follows:

(Units in Thousands)	2017	2016	2015
Granted units	51	49	60
Grant date fair value	\$ 46.05	\$ 40.68	\$ 34.58

A summary of the stock equivalent unit changes for the year ended 2017 are as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2017	750	\$ 27.39
Granted	51	46.05
Units distributed	(71)	20.52
Dividend equivalents	23	45.24
Stock equivalent units at Dec. 31, 2017	<u>753</u>	<u>29.83</u>

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective in 2010) and 2015 Omnibus Incentive Plan. The plans allow Xcel Energy to attach various performance goals to the awards granted. The liability awards granted have been historically dependent on a single measure of performance, Xcel Energy Inc.'s relative TSR measured over a three-year period. For 2017, 2016 and 2015 awards, Xcel Energy Inc.'s TSR is compared to the TSR of other companies in a 22-member utilities peer group. At the end of the three-year period, potential payouts of the awards range from zero to 200 percent, depending on Xcel Energy Inc.'s TSR compared to the applicable peer group or index.

The TSR liability awards granted for the years ended Dec. 31 were as follows:

(In Thousands)	2017	2016	2015
Awards granted	240	264	224

The total amounts of TSR liability awards settled during the years ended Dec. 31 were as follows:

(In Thousands)	2017	2016	2015
Awards settled	454	354	—
Settlement amount (cash, common stock and deferred amounts)	\$ 19,083	\$ 13,724	\$ —

The amount of cash used to settle Xcel Energy's TSR liability awards was \$7 million in 2017.

Share-Based Compensation Expense — Other than for restricted stock, the vesting of employee equity awards is generally predicated on the achievement of a performance condition, which is the achievement of a TSR, EPS or environmental measures target. Additionally, approximately 0.3 million of equity award units were granted annually in 2017, 2016, and 2015, respectively, with vesting subject only to service conditions for periods of three years. Generally, all of these instruments are considered to be equity awards since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. The grant date fair value of equity awards is expensed over the service period as employees vest in their rights to those awards.

The 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.

The compensation costs related to share-based awards for the years ended Dec. 31 were as follows:

(Millions of Dollars)	2017	2016	2015
Compensation cost for share-based awards ^(a)	\$ 57	\$ 41	\$ 45
Tax benefit recognized in income	22	16	18

(a) Compensation costs for share-based payment arrangements are included in O&M expense in the consolidated statements of income.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2015 Omnibus Incentive Plan (effective May 20, 2015) is 7.0 million shares. The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) is 8.3 million shares. Under the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010), the total number of shares approved for issuance is 1.2 million shares.

As of Dec. 31, 2017 and 2016, there was approximately \$44 million and \$29 million, respectively, of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the amount unrecognized at Dec. 31, 2017 over a weighted average period of 1.7 years.

9. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 46 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. As of Dec. 31, 2017:

- NSP-Minnesota had 1,858 and NSP-Wisconsin had 383 bargaining employees covered under a collective-bargaining agreement, which expires in December 2019. NSP-Minnesota also had an additional 248 nuclear operation bargaining employees covered under several collective-bargaining agreements. These agreements expire in 2018 and 2019.
- PSCo had 1,835 bargaining employees covered under a collective-bargaining agreement, which expired in May 2017. While collective bargaining is ongoing, the terms and conditions of the agreement are automatically extended.
- SPS had 791 bargaining employees covered under a collective-bargaining agreement, which expires in October 2019.

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

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

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

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

Specific valuation methods include the following:

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

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

Investments in commingled funds, equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with a few days' notice to annually with 90 days' notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Depending on the fund, unscheduled distributions from real estate investments may require approval of the fund or may be redeemed with proper notice, which is typically quarterly with 45-90 days' notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity.

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

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Pension Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy’s consolidated operating cash flows. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2017 and 2016 were \$37 million and \$44 million, respectively. In 2017 and 2016, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$5 million and \$8 million, respectively.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan, supplemented by Xcel Energy’s consolidated operating cash flows as determined necessary. For more information regarding the funding of rabbi trusts, see Note 11 to the consolidated financial statements. Also in 2016, Xcel Energy amended the deferred compensation plan to provide eligible participants the ability to diversify deferred settlements of equity awards, other than time-based equity awards, into various fund options.

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

- Investment returns in 2017 were above the assumed level of 6.87 percent;
- Investment returns in 2016 were below the assumed level of 6.87 percent;
- Investment returns in 2015 were below the assumed level of 7.09 percent; and
- In 2018, Xcel Energy’s expected investment-return assumption is 6.87 percent.

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

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

	<u>2017</u>	<u>2016</u>
Domestic and international equity securities	36%	38%
Long-duration fixed income and interest rate swap securities	27	27
Short-to-intermediate fixed income securities	20	16
Alternative investments	15	17
Cash	2	2
Total	<u>100%</u>	<u>100%</u>

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

Pension Plan Assets

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

(Millions of Dollars)	Dec. 31, 2017				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents.....	\$ 196	\$ —	\$ —	\$ —	\$ 196
Commingled funds:					
U.S. equity funds.....	513	—	—	—	513
Non U.S. equity funds.....	92	—	—	199	291
U.S. corporate bond funds.....	369	—	—	—	369
Emerging market equity funds.....	—	—	—	314	314
Emerging market debt funds.....	75	—	—	166	241
Private equity investments.....	—	—	—	84	84
Real estate.....	—	—	—	195	195
Other commingled funds.....	5	—	—	117	122
Debt securities:					
Government securities.....	—	356	—	—	356
U.S. corporate bonds.....	—	272	—	—	272
Non U.S. corporate bonds.....	—	45	—	—	45
Equity securities:					
U.S. equities.....	114	—	—	—	114
Other.....	(29)	4	—	1	(24)
Total.....	<u>\$ 1,335</u>	<u>\$ 677</u>	<u>\$ —</u>	<u>\$ 1,076</u>	<u>\$ 3,088</u>

(Millions of Dollars)	Dec. 31, 2016				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents.....	\$ 113	\$ —	\$ —	\$ —	\$ 113
Commingled funds:					
U.S. equity funds.....	491	—	—	—	491
Non U.S. equity funds.....	167	—	—	202	369
U.S. corporate bond funds.....	268	—	—	—	268
Emerging market equity funds.....	—	—	—	194	194
Emerging market debt funds.....	79	—	—	85	164
Commodity funds.....	—	—	—	21	21
Private equity investments.....	—	—	—	101	101
Real estate.....	—	—	—	184	184
Other commingled funds.....	—	—	—	210	210
Debt securities:					
Government securities.....	—	364	—	—	364
U.S. corporate bonds.....	—	238	—	—	238
Non U.S. corporate bonds.....	—	38	—	—	38
Mortgage-backed securities.....	—	6	—	—	6
Asset-backed securities.....	—	3	—	—	3
Equity securities:					
U.S. equities.....	89	—	—	—	89
Other.....	—	3	—	—	3
Total.....	<u>\$ 1,207</u>	<u>\$ 652</u>	<u>\$ —</u>	<u>\$ 997</u>	<u>\$ 2,856</u>

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

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

(Millions of Dollars)	2017	2016
Accumulated Benefit Obligation at Dec. 31	\$ 3,612	\$ 3,489
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 3,682	\$ 3,568
Service cost	94	92
Interest cost	147	160
Plan amendments	(13)	2
Actuarial loss	259	186
Benefit payments ^(a)	(341)	(326)
Obligation at Dec. 31	<u>\$ 3,828</u>	<u>\$ 3,682</u>

(Millions of Dollars)	2017	2016
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 2,856	\$ 2,884
Actual return on plan assets	411	172
Employer contributions	162	125
Benefit payments ^(a)	(341)	(325)
Fair value of plan assets at Dec. 31	<u>\$ 3,088</u>	<u>\$ 2,856</u>

(Millions of Dollars)	2017	2016
Funded Status of Plans at Dec. 31:		
Funded status ^(b)	\$ (740)	\$ (826)

^(a) 2017 amount includes approximately \$174 million of lump-sum benefit payments used in the determination of a settlement charge.

^(b) Amounts are recognized in noncurrent liabilities on Xcel Energy's consolidated balance sheets.

(Millions of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 1,709	\$ 1,836
Prior service credit	(25)	(5)
Total	<u>\$ 1,684</u>	<u>\$ 1,831</u>

(Millions of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	\$ 100	\$ 101
Noncurrent regulatory assets	1,511	1,650
Deferred income taxes	19	31
Net-of-tax accumulated OCI	54	49
Total	<u>\$ 1,684</u>	<u>\$ 1,831</u>

Measurement date

	2017	2016
	Dec. 31, 2017	Dec. 31, 2016

Significant Assumptions Used to Measure Benefit Obligations:

	2017	2016
Discount rate for year-end valuation	3.63%	4.13%
Expected average long-term increase in compensation level	3.75	3.75
Mortality table	RP-2014	RP-2014

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

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

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

- \$150 million in January 2018;
- \$162 million in 2017;
- \$125 million in 2016; and
- \$90 million in 2015.

For future years, Xcel Energy anticipates contributions will be made as necessary.

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

Benefit Costs — The components of Xcel Energy’s net periodic pension cost were:

(Millions of Dollars)	2017	2016	2015
Service cost	\$ 94	\$ 92	\$ 99
Interest cost	147	160	149
Expected return on plan assets	(209)	(210)	(214)
Amortization of prior service credit	(2)	(2)	(2)
Amortization of net loss	107	97	125
Settlement charge ^(a)	81	—	—
Net periodic pension cost	<u>218</u>	<u>137</u>	<u>157</u>
Costs not recognized due to effects of regulation	(79)	(15)	(29)
Net benefit cost recognized for financial reporting	<u>\$ 139</u>	<u>\$ 122</u>	<u>\$ 128</u>

^(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 the fourth quarter of 2017 as a result of lump-sum distributions during the 2017 plan year, Xcel Energy recorded a total pension settlement charge of \$81 million, the majority of which was not recognized due to the effects of regulation. A total of \$8 million of that amount was recorded in O&M expenses in the fourth quarter of 2017.

Significant Assumptions Used to Measure Costs:	2017	2016	2015
Discount rate	4.13%	4.66%	4.11%
Expected average long-term increase in compensation level	3.75	4.00	3.75
Expected average long-term rate of return on assets	6.87	6.87	7.09

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2018 pension cost calculations is 6.87 percent.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total expense to these plans was approximately \$37 million in 2017, \$36 million in 2016 and \$34 million in 2015.

Postretirement Health Care Benefits

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

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

Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional 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.

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

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

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its asset portfolio. The 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 projected asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by postretirement health care assets in any year.

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

(Millions of Dollars)	<u>Dec. 31, 2017</u>				
	<u>Level 1</u>	<u>Level 2</u>	<u>Level 3</u>	<u>Investments Measured at NAV</u>	<u>Total</u>
Cash equivalents	\$ 29	\$ —	\$ —	\$ —	\$ 29
Insurance contracts	—	50	—	—	50
Commingled funds:					
U.S. equity funds	74	—	—	—	74
U.S. fixed income funds	34	—	—	—	34
Emerging market debt funds	40	—	—	—	40
Debt securities:					
Government securities	—	57	—	—	57
U.S. corporate bonds	—	63	—	—	63
Non U.S. corporate bonds	—	21	—	—	21
Asset-backed securities	—	23	—	—	23
Mortgage-backed securities	—	34	—	—	34
Equity securities:					
Non U.S. equities	35	—	—	—	35
Other	—	1	—	—	1
Total	<u>\$ 212</u>	<u>\$ 249</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 461</u>

Dec. 31, 2016

(Millions of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 21	\$ —	\$ —	\$ —	\$ 21
Insurance contracts	—	47	—	—	47
Commingled funds:					
U.S. equity funds	54	—	—	—	54
U.S. fixed income funds	27	—	—	—	27
Emerging market debt funds	30	—	—	—	30
Other commingled funds	—	—	—	55	55
Debt securities:					
Government securities	—	38	—	—	38
U.S. corporate bonds	—	62	—	—	62
Non U.S. corporate bonds	—	17	—	—	17
Asset-backed securities	—	19	—	—	19
Mortgage-backed securities	—	29	—	—	29
Equity securities:					
Non U.S. equities	41	—	—	—	41
Other	—	2	—	—	2
Total	<u>\$ 173</u>	<u>\$ 214</u>	<u>\$ —</u>	<u>\$ 55</u>	<u>\$ 442</u>

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

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

(Millions of Dollars)	2017	2016
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 603	\$ 584
Service cost	2	2
Interest cost	24	26
Medicare subsidy reimbursements	1	2
Plan participants' contributions	8	7
Actuarial loss	33	33
Benefit payments	(50)	(51)
Obligation at Dec. 31	<u>\$ 621</u>	<u>\$ 603</u>

(Millions of Dollars)	2017	2016
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 442	\$ 448
Actual return on plan assets	41	20
Plan participants' contributions	8	7
Employer contributions	20	18
Benefit payments	(50)	(51)
Fair value of plan assets at Dec. 31	<u>\$ 461</u>	<u>\$ 442</u>

(Millions of Dollars)	2017	2016
Funded Status of Plans at Dec. 31:		
Funded status	<u>\$ (160)</u>	<u>\$ (161)</u>
Current liabilities	(3)	(6)
Noncurrent liabilities	(157)	(155)
Net postretirement amounts recognized on consolidated balance sheets	<u>\$ (160)</u>	<u>\$ (161)</u>

(Millions of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 147	\$ 136
Prior service credit	(44)	(54)
Total	<u>\$ 103</u>	<u>\$ 82</u>

(Millions of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Noncurrent regulatory assets	\$ 107	\$ 91
Current regulatory liabilities	(1)	(1)
Noncurrent regulatory liabilities	(10)	(14)
Deferred income taxes	2	2
Net-of-tax accumulated OCI	5	4
Total	<u>\$ 103</u>	<u>\$ 82</u>

Measurement date Dec. 31, 2017 Dec. 31, 2016

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

Beginning with the Dec. 31, 2017 measurement, Xcel Energy Inc. separated its initial medical trend assumption for pre-Medicare (Pre-65) and post-Medicare (Post-65) claims costs in order to reflect different short-term expectations based on recent experience differences. The Post-65 initial medical trend rate was set at 5.5 percent. The Pre-65 initial medical trend rate was set at 7.0 percent. The ultimate trend assumption remained at 4.5 percent for both groups. The period until the ultimate rate is reached is five years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

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

(Millions of Dollars)	One-Percentage Point	
	Increase	Decrease
APBO	\$ 60	\$ (51)
Service and interest components	3	(2)

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

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

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

(Millions of Dollars)	2017	2016	2015
Service cost	\$ 2	\$ 2	\$ 2
Interest cost	24	26	25
Expected return on plan assets	(25)	(25)	(26)
Amortization of prior service credit	(11)	(11)	(11)
Amortization of net loss	7	4	6
Net periodic postretirement (credit) cost	<u>\$ (3)</u>	<u>\$ (4)</u>	<u>\$ (4)</u>

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

Projected Benefit Payments

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

(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
2018.....	\$ 307	\$ 47	\$ 2	\$ 45
2019.....	262	47	2	45
2020.....	261	47	2	45
2021.....	261	47	3	44
2022.....	266	46	3	43
2023-2027	1,274	212	14	198

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.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2017, 2016 and 2015. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 576 in 2017 from 700 in 2016. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota and NSP-Wisconsin in multiemployer plans for the years presented:

(Millions of Dollars)	2017	2016	2015
Multiemployer pension contributions:			
NSP-Minnesota.....	\$ 12	\$ 14	\$ 17
NSP-Wisconsin	—	1	1
Total	<u>\$ 12</u>	<u>\$ 15</u>	<u>\$ 18</u>

10. Other Income, Net

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

(Millions of Dollars)	2017	2016	2015
Interest income	\$ 19	\$ 8	\$ 6
Other nonoperating income	7	3	4
Insurance policy expense	(3)	(3)	(4)
Other income, net.....	<u>\$ 23</u>	<u>\$ 8</u>	<u>\$ 6</u>

11. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

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

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

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

Specific valuation methods include the following:

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

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, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity.

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

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. 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 of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, 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, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were \$560 million and \$379 million as of Dec. 31, 2017 and 2016, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were \$7 million and \$47 million as of Dec. 31, 2017 and 2016, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund as of Dec. 31, 2017 and 2016:

(Millions of Dollars)	Dec. 31, 2017						
	Cost	Fair Value				Investments Measured at NAV	Total
		Level 1	Level 2	Level 3			
Nuclear decommissioning fund ^(a)							
Cash equivalents	\$ 29	\$ 29	\$ —	\$ —	\$ —	\$ 29	
Commingled funds:							
Non U.S. equities	264	217	—	—	90	307	
Emerging market debt funds	156	—	—	—	166	166	
Private equity investments	141	—	—	—	198	198	
Real estate	131	—	—	—	202	202	
Other commingled funds	9	6	—	—	3	9	
Debt securities:							
Government securities	68	—	69	—	—	69	
U.S. corporate bonds	320	—	322	—	—	322	
Non U.S. corporate bonds	50	—	50	—	—	50	
Equity securities:							
U.S. equities	271	557	—	—	—	557	
Non U.S. equities	152	234	—	—	—	234	
Total	\$ 1,591	\$ 1,043	\$ 441	\$ —	\$ 659	\$ 2,143	

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

(Millions of Dollars)	Cost	Fair Value				Investments Measured at NAV	Total
		Level 1	Level 2	Level 3			
Nuclear decommissioning fund ^(a)							
Cash equivalents	\$ 20	\$ 20	\$ —	\$ —	\$ —	\$ 20	
Commingled funds:							
Non U.S. equities	261	133	—	—	112	245	
Emerging market debt funds	93	—	—	—	98	98	
Commodity funds	106	—	—	—	92	92	
Private equity investments	132	—	—	—	190	190	
Real estate	129	—	—	—	188	188	
Other commingled funds	151	—	—	—	160	160	
Debt securities:							
Government securities	33	—	32	—	—	32	
U.S. corporate bonds	105	—	106	—	—	106	
Non U.S. corporate bonds	22	—	21	—	—	21	
Municipal bonds	14	—	14	—	—	14	
Mortgage-backed securities	3	—	3	—	—	3	
Equity securities:							
U.S. equities	271	474	—	—	—	474	
Non U.S. equities	189	218	—	—	—	218	
Total	<u>\$ 1,529</u>	<u>\$ 845</u>	<u>\$ 176</u>	<u>\$ —</u>	<u>\$ 840</u>	<u>\$ 1,861</u>	

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes \$133 million of equity investments in unconsolidated subsidiaries and \$98 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2017 and 2016 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, as of Dec. 31, 2017:

(Millions of Dollars)	Final Contractual Maturity				Total
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	
Government securities	\$ —	\$ 2	\$ —	\$ 67	\$ 69
U.S. corporate bonds	5	85	174	58	322
Non U.S. corporate bonds	—	15	31	4	50
Debt securities	<u>\$ 5</u>	<u>\$ 102</u>	<u>\$ 205</u>	<u>\$ 129</u>	<u>\$ 441</u>

Rabbi Trusts

In June 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of its supplemental executive retirement plan and deferred compensation plan. The following table presents the cost and fair value of the assets held in rabbi trusts as of Dec. 31, 2017 and 2016:

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

Dec. 31, 2016

(Millions of Dollars)	Fair Value				
	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts ^(a)					
Cash equivalents	\$ 48	\$ 48	\$ —	\$ —	\$ 48
Mutual funds	2	2	—	—	2
Total	<u>\$ 50</u>	<u>\$ 50</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 50</u>

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

Derivative Instruments 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, 2017, accumulated other comprehensive losses related to interest rate derivatives included \$3 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for unsettled hedges, as applicable.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the 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, 2017, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2018. Xcel Energy enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2017 and 2016.

As of Dec. 31, 2017, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included immaterial net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, 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.

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

(Amounts in Millions) ^{(a)(b)}	2017	2016
MWh of electricity	68	47
MMBtu of natural gas	37	122

^(a) Amounts are not reflective of net positions in the underlying commodities.

^(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty’s ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy’s own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

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

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, 2017, four of Xcel Energy’s 10 most significant counterparties for these activities, comprising \$45 million or 29 percent of this credit exposure, had investment grade credit ratings from S&P’s, Moody’s or Fitch Ratings. Five of the 10 most significant counterparties, comprising \$30 million or 19 percent 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. Another of these significant counterparties, comprising \$7 million or 5 percent of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. Eight of these significant counterparties are municipal or cooperative electric entities or other utilities.

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

(Millions of Dollars)	2017	2016	2015
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ (51)	\$ (55)	\$ (58)
After-tax net realized losses on derivative transactions reclassified into earnings	3	4	3
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	<u>\$ (48)</u>	<u>\$ (51)</u>	<u>\$ (55)</u>

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

(Millions of Dollars)	Year Ended Dec. 31, 2017				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 5 ^(a)	\$ —	\$ —
Total	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 5</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 10 ^(b)
Electric commodity	—	10	—	(15) ^(c)	—
Natural gas commodity	—	(13)	—	3 ^(d)	(6) ^(d)
Total	<u>\$ —</u>	<u>\$ (3)</u>	<u>\$ —</u>	<u>\$ (12)</u>	<u>\$ 4</u>

Year Ended Dec. 31, 2016

(Millions of Dollars)	Pre-Tax Fair Value Gains Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 6 ^(a)	\$ —	\$ —
Total	\$ —	\$ —	\$ 6	\$ —	\$ —
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 2 ^(b)
Electric commodity	—	17	—	(8) ^(c)	—
Natural gas commodity	—	1	—	15 ^(d)	(8) ^(d)
Total	\$ —	\$ 18	\$ —	\$ 7	\$ (6)

Year Ended Dec. 31, 2015

(Millions of Dollars)	Pre-Tax Fair Value Losses Recognized During the Period in:		Pre-Tax Losses Reclassified into Income During the Period from:		Pre-Tax Losses Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 5 ^(a)	\$ —	\$ —
Total	\$ —	\$ —	\$ 5	\$ —	\$ —
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ (7) ^(b)
Electric commodity	—	(19)	—	16 ^(c)	—
Natural gas commodity	—	(16)	—	16 ^(d)	(12) ^(d)
Total	\$ —	\$ (35)	\$ —	\$ 32	\$ (19)

(a) Amounts are recorded to interest charges.

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

(c) Amounts are 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) Certain derivatives are utilized to mitigate natural gas price risk for electric generation and are recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Amounts for the years ended Dec. 31, 2017 and Dec. 31, 2016 included immaterial settlement gains and losses. Amounts for the year ended Dec. 31, 2015 included \$1 million of settlement losses. The remaining settlement losses for the years ended Dec. 31, 2017, 2016 and 2015 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

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

Credit Related Contingent Features — Contract provisions for derivative instruments that 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 that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2017 and 2016, there were no derivative instruments in a material liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that 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, 2017 and 2016.

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

(Millions of Dollars)	Dec. 31, 2017					
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total
	Level 1	Level 2	Level 3			
Current derivative assets						
Commodity trading	\$ 2	\$ 22	\$ —	\$ 24	\$ (15)	\$ 9
Electric commodity	—	—	32	32	(2)	30
Total current derivative assets	\$ 2	\$ 22	\$ 32	\$ 56	\$ (17)	\$ 39
PPAs ^(a)						5
Current derivative instruments						\$ 44
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	\$ —	\$ 31	\$ 5	\$ 36	\$ (7)	\$ 29
Total noncurrent derivative assets	\$ —	\$ 31	\$ 5	\$ 36	\$ (7)	\$ 29
PPAs ^(a)						19
Noncurrent derivative instruments						\$ 48

(Millions of Dollars)	Dec. 31, 2017					
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total
	Level 1	Level 2	Level 3			
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ 2	\$ 18	\$ —	\$ 20	\$ (15)	\$ 5
Electric commodity	—	—	2	2	(2)	—
Natural gas commodity	—	1	—	1	—	1
Total current derivative liabilities	\$ 2	\$ 19	\$ 2	\$ 23	\$ (17)	\$ 6
PPAs ^(a)						23
Current derivative instruments						\$ 29
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ —	\$ 24	\$ —	\$ 24	\$ (10)	\$ 14
Total noncurrent derivative liabilities	\$ —	\$ 24	\$ —	\$ 24	\$ (10)	\$ 14
PPAs ^(a)						112
Noncurrent derivative instruments						\$ 126

(a) 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.

(b) 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, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$3 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

(Millions of Dollars)	Dec. 31, 2016					
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total
	Level 1	Level 2	Level 3			
Current derivative assets						
Other derivative instruments:						
Commodity trading	\$ 13	\$ 14	\$ —	\$ 27	\$ (20)	\$ 7
Electric commodity	—	—	19	19	(2)	17
Natural gas commodity	—	9	—	9	—	9
Total current derivative assets	<u>\$ 13</u>	<u>\$ 23</u>	<u>\$ 19</u>	<u>\$ 55</u>	<u>\$ (22)</u>	<u>33</u>
PPAs ^(a)						5
Current derivative instruments						<u>\$ 38</u>
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	\$ —	\$ 31	\$ —	\$ 31	\$ (7)	\$ 24
Natural gas commodity	—	2	—	2	—	2
Total noncurrent derivative assets	<u>\$ —</u>	<u>\$ 33</u>	<u>\$ —</u>	<u>\$ 33</u>	<u>\$ (7)</u>	<u>26</u>
PPAs ^(a)						24
Noncurrent derivative instruments						<u>\$ 50</u>

(Millions of Dollars)	Dec. 31, 2016					
	Fair Value			Fair Value Total	Counterparty Netting ^(b)	Total
	Level 1	Level 2	Level 3			
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ 14	\$ 11	\$ —	\$ 25	\$ (21)	\$ 4
Electric commodity	—	—	2	2	(2)	—
Total current derivative liabilities	<u>\$ 14</u>	<u>\$ 11</u>	<u>\$ 2</u>	<u>\$ 27</u>	<u>\$ (23)</u>	<u>4</u>
PPAs ^(a)						23
Current derivative instruments						<u>\$ 27</u>
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ —	\$ 24	\$ —	\$ 24	\$ (11)	\$ 13
Total noncurrent derivative liabilities	<u>\$ —</u>	<u>\$ 24</u>	<u>\$ —</u>	<u>\$ 24</u>	<u>\$ (11)</u>	<u>13</u>
PPAs ^(a)						135
Noncurrent derivative instruments						<u>\$ 148</u>

(a) 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.

(b) 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, 2016. At Dec. 31, 2016, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$4 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2017, 2016 and 2015:

(Millions of Dollars)	Year Ended Dec. 31		
	2017	2016	2015
Balance at Jan. 1	\$ 17	\$ 18	\$ 56
Purchases	82	35	64
Settlements	(97)	(89)	(70)
Net transactions recorded during the period:			
Gains recognized in earnings ^(a)	5	—	2
Net gains (losses) recognized as regulatory assets and liabilities	28	53	(34)
Balance at Dec. 31	<u>\$ 35</u>	<u>\$ 17</u>	<u>\$ 18</u>

(a) These 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 the years ended Dec. 31, 2017, 2016 and 2015.

Fair Value of Long-Term Debt

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

(Millions of Dollars)	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$ 14,976	\$ 16,531	\$ 14,450	\$ 15,513

The 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. The fair value estimates are based on information available to management as of Dec. 31, 2017 and 2016, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

12. Rate Matters

Tax Reform — Regulatory Proceedings

The specific impacts of the TCJA on retail customer rates are subject to regulatory approval. Xcel Energy is in the process of quantifying the rate impacts of the TCJA and addressing these impacts in its open and recently concluded proceedings focused on retail base rate impacts for its utility subsidiaries. In addition, several states have opened dockets on the impact of tax reform, with the expectation that currently effective rates in those jurisdictions will be adjusted.

NSP-Minnesota — A docket has been opened in Minnesota. NSP-Minnesota will provide a detailed filing to the MPUC by March 2, 2018, which will estimate the impact of the TCJA on the latest electric and natural gas rate case filings and corporate forecasts.

Dockets have also been opened in North Dakota and South Dakota. In February 2018, NSP-Minnesota provided the NDPSC a preliminary quantification of the impact of the TCJA on electric and natural gas revenue requirements. NSP-Minnesota proposed multi-year moratoriums on electric and natural gas rate case filings. NSP-Minnesota also filed comments with the SDPUC and proposed using the reduced revenue requirements from the TCJA to defer planned future rate filings.

NSP-Wisconsin — In January 2018, the PSCW issued an order requiring public utilities to apply deferred accounting for the impacts of the TCJA. The PSCW has also requested that utilities provide responses to questions on tax reform and its impact on electric and natural gas revenue requirements. In February 2018, NSP-Wisconsin proposed leveling upcoming rate cases, advancing infrastructure investments and buying down assets such as the regulatory asset for Ashland clean-up.

PSCo — The impacts associated with the TCJA on PSCo’s retail customer rates are being addressed in several proceedings, which include the following:

- ***Colorado Statewide TCJA Proceeding*** — On Jan. 31, 2018, the CPUC opened a statewide TCJA proceeding and ordered deferred accounting for all investor-owned utilities. On Feb. 21, 2017, PSCo filed a response with the CPUC related to the deferred accounting order and statewide TCJA proceeding, addressing the estimated impacts along with other considerations given PSCo’s pending natural gas and electric rate cases.
- ***Colorado 2017 Multi-Year Natural Gas Rate Case*** — On Feb. 14, 2018, the ALJ approved PSCo and CPUC Staff’s non-unanimous settlement agreement which addresses the impacts of the TCJA in 2018. This settlement agreement includes a \$20 million reduction to provisional rates effective March 1, 2018, with future true-ups to be determined later in 2018 once a full analysis of the comprehensive impacts of tax reform is performed, including any outcomes associated with statewide proceeding. The final true-up would provide customers the full net benefit of the TCJA effective Jan. 1, 2018.
- ***Colorado 2017 Multi-Year Electric Rate Case*** — On Feb. 16, 2018, the CPUC denied the proposed settlement agreement between PSCo and several intervenors, in favor of the state TCJA proceeding. In the second quarter of 2018, PSCo plans to file a revised rate request that will include the impacts of the TCJA. Provisional rates, subject to refund with interest, are expected to be effective June 1, 2018. The appropriate test year and the final approved revenue requirement will be determined in the pending rate case, discussed below. PSCo expects to defer the TCJA net benefits for the first five months of 2018, prior to provisional rates.

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

SPS — On Jan. 25, 2018, the PUCT issued an order requiring utilities to apply deferred accounting for the impacts of the TCJA. On Feb. 16, 2018, SPS provided the PUCT supplemental testimony on the impacts of the TCJA for its ongoing Texas 2017 electric rate case, including increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings.

In February 2018, SPS provided the NMPRC a preliminary quantification of the impacts of the TCJA on its ongoing New Mexico 2017 electric rate case. SPS also recommended increasing its equity ratio to 58 percent to offset the negative impact of the TCJA on its credit metrics and potentially its credit ratings. In a separate NMPRC investigation into the impacts of the TCJA on regulated utilities in New Mexico, SPS provided additional information on the impacts of the TCJA on 2018 operations on Feb. 23, 2018.

FERC Formula Rates — The FERC has not yet issued guidance on how and when utilities should reflect the impacts of the TCJA in formula rates. However, FERC-approved formula rates for wholesale customers are generally adjusted on an annual basis for certain changes in rate base and actual operating expenses, including income taxes. As a result, these revenues would be subject to an automatic reduction for the effect of the TCJA tax rate change, absent specific FERC action.

NSP-Minnesota and NSP-Wisconsin were parties to a February 2018 FERC filing by MISO and MISO TOs proposing to early commence reductions to transmission formula rates in 2018 for tax rate impacts of the TCJA. Also in February 2018, PSCo made a filing with FERC similarly requesting early reductions in its transmission and production formula rates in 2018 for tax rate impacts of the TCJA. For SPS, as the TCJA tax rate change largely offsets a depreciation rate change that was effective Jan. 1, 2018 in its wholesale production rates, SPS has notified FERC that it will continue to charge rates established in 2017, subject to refund. FERC has not issued any orders on these matters, or commenced any formula rate proceedings related the impacts of the TCJA.

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — MPUC

Minnesota 2016 Multi-Year Electric Rate Case — In June 2017, the MPUC issued a written order approving an estimated total rate increase of approximately \$240 million over the four-year period covering 2016-2019.

Key terms:

- Four-year period covering 2016-2019;
- Annual sales true-up with decoupling subject to a 3 percent cap on surcharges;
 - In February 2018, NSP-Minnesota reported the 2017 sales true-up and revenue decoupling surcharge amounts of \$22 million and \$27 million, respectively, to be collected beginning April 1, 2018 through March 31, 2019.
- ROE of 9.2 percent and an equity ratio of 52.5 percent;
- Nuclear related costs will not be considered provisional;
- Continued use of all existing electric riders, however no new electric riders may be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019;
- Four-year stay out provision for rate cases;
- Property tax true-up mechanism for 2017-2019; and
- Capital expenditure true-up mechanism for 2016-2019.

<u>(Millions of Dollars, incremental)</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>Total</u>
Revenues	\$ 75	\$ 55	\$ —	\$ 50	\$ 180
NSP-Minnesota’s sales true-up	60	—	—	—	60
Total rate impact	<u>\$ 135</u>	<u>\$ 55</u>	<u>\$ —</u>	<u>\$ 50</u>	<u>\$ 240</u>

Monticello Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 MW in 2015. The Monticello LCM/EPU project expenditures were approximately \$665 million. Total capitalized costs were approximately \$748 million, which includes AFUDC. In 2008, project expenditures were initially estimated at approximately \$320 million, excluding AFUDC.

In 2015, the MPUC voted to allow for full recovery, including a return, on \$415 million of the total plant costs (inclusive of AFUDC), but only allow recovery of the remaining \$333 million of costs with no return on this portion of the investment. As a result, Xcel Energy recorded a pre-tax loss of \$129 million in the first quarter of 2015, after which the remaining book value of the Monticello project represented the present value of the estimated future cash flows.

2017 and 2018 TCR Filing — In November 2017, NSP-Minnesota submitted a TCR filing with the MPUC, requesting a combined recovery of approximately \$110 million of transmission investment costs not included in electric base rates for 2017 and 2018. In accordance with NSP-Minnesota's most recent electric rate case, three CapX2020 transmission projects currently included in the TCR rider remain in the rider through the multi-year plan period. NSP-Minnesota has also proposed recovery of one additional project related to grid modernization. An MPUC decision is expected in 2018.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — CIP expenses are recovered through base rates and a rider that is adjusted annually. The estimated electric and natural gas incentives for 2017 are expected to be \$32 million and \$3 million, respectively, based on the approved savings goals in NSP-Minnesota's CIP Triennial Plan. The plan sets an annual electric goal of saving the equivalent of 1.5 percent of the volume of electric energy sales and an annual natural gas goal of saving 1.0 percent of the volume of gas energy sales. In 2017 the MPUC approved the following for NSP-Minnesota:

- The 2016 CIP electric and natural gas financial incentives totaling \$48 million and \$6 million, respectively; and
- The proposed 2017 electric and natural gas CIP riders with estimated 2017 recovery of \$59 million of electric CIP expenses and \$18 million of natural gas CIP expenses. The proposed recovery through the riders is in addition to an estimated \$89 million and \$4 million through electric and gas base rates, respectively.

GUIC Rider — In February 2018, the MPUC approved a 2017 revenue requirement of approximately \$20 million for GUIC investments. New rates are expected to be in effect in March 2018. In November 2017, NSP-Minnesota filed the 2018 GUIC rider with the MPUC requesting recovery of approximately \$28 million from Minnesota gas utility customers. Costs in both filings include funding for pipeline assessments as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. The MPUC is currently considering the 2018 petition.

Annual Automatic Adjustment of Fuel Clause Charges — In May 2017, the MPUC voted to disallow approximately \$4 million of replacement energy costs for the PI nuclear facility outages allocated to the Minnesota jurisdiction in 2015. This disallowance was recognized in the second quarter of 2017. In December 2017, the MPUC issued an order to hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages under certain circumstances. In January 2018, NSP-Minnesota filed a petition for clarification of the order. The outcome of the petition is uncertain.

NSP-Wisconsin

Recently Concluded Regulatory Proceedings — PSCW

Wisconsin 2018 Electric and Gas Rate Case — In May 2017, NSP-Wisconsin filed a request with the PSCW to increase electric rates by \$25 million, or 3.6 percent, and natural gas rates by \$12 million, or 10.1 percent, effective Jan. 1, 2018. The rate filing was based on a 2018 FTY, a ROE of 10.0 percent, an equity ratio of 52.53 percent and a forecasted rate base of approximately \$1.2 billion for the electric utility and \$138 million for the natural gas utility.

In December 2017, the PSCW approved electric and natural gas rate increases of approximately \$9 million, or 1.4 percent, and \$10 million, or 8.3 percent, respectively, based on a 9.8 percent ROE and an equity ratio of 51.45 percent. New rates went into effect on Jan. 1, 2018.

Pending Regulatory Proceedings — CPUC

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

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

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

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

Key dates in the procedural schedule are as follows:

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

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

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

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

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

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

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

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

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

Electric, Purchased Gas and Resource Adjustment Clauses

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

SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

Appeal of the Texas 2015 Electric Rate Case Decision — In 2014, SPS had requested an overall retail electric revenue rate increase of \$42 million. In 2015, the PUCT approved an overall rate decrease of approximately \$4 million, net of rate case expenses. In April 2016, SPS filed an appeal with the Texas State District Court (District Court) challenging the PUCT’s order that had denied SPS’ request for rehearing on certain items in SPS’ Texas 2015 electric rate case related to capital structure, incentive compensation and wholesale load reductions. In March 2017, the District Court denied SPS’ appeal. In April 2017, SPS appealed the District Court’s decision to the Court of Appeals. A decision is pending.

Texas 2017 Electric Rate Case — In 2017, SPS filed a \$55 million, or 5.8 percent, retail electric, non-fuel base rate increase case in Texas with each of its Texas municipalities and the PUCT. The request was based on the 12-month period ended June 30, 2017, with the final three months based on estimates, a requested ROE of 10.25 percent, a Texas retail electric rate base of approximately \$1.9 billion and an equity ratio of 53.97 percent.

The following table summarizes SPS’ rate increase request:

Revenue Request (Millions of Dollars)	
Incremental revenue request	\$ 69
TCRF revenue conversion to base rates ^(a)	(14)
Net revenue increase request	<u>\$ 55</u>

^(a) The roll-in of the TCRF rider revenue into base rates will not have an impact on customer bills or revenue as these costs are already being recovered through the rider. SPS can request another TCRF rider after the conclusion of this rate case to recover transmission investments subsequent to June 30, 2017.

Key dates in the revised procedural schedule are as follows:

- Intervenors’ direct testimony — April 25, 2018;
- PUCT Staff direct testimony — May 2, 2018;
- PUCT Staff and intervenors’ cross-rebuttal testimony — May 14, 2018;
- SPS’ rebuttal testimony — May 23, 2018; and
- Hearings — June 4 - 14, 2018.

The final rates are expected to be effective retroactive to Jan. 23, 2018 through a customer surcharge. A PUCT decision is expected in the fourth quarter of 2018. As discussed above, the PUCT has opened a docket on the impact of the TCJA, which may have a significant impact on this rate case. On Feb. 16, 2018, SPS provided additional information on the impacts of the TCJA.

Pending Regulatory Proceedings — NMPRC

Appeal of the New Mexico 2016 Electric Rate Case Dismissal — In November 2016, SPS filed an electric rate case with the NMPRC seeking an increase in base rates of approximately \$41 million, representing a total revenue increase of approximately 10.9 percent. The rate filing was based on a requested ROE of 10.1 percent, an equity ratio of 53.97 percent, an electric rate base of approximately \$832 million and a FTY ending June 30, 2018. In April 2017, the NMPRC dismissed SPS' rate case. In May 2017, SPS filed a notice of appeal to the New Mexico Supreme Court. A decision is pending.

New Mexico 2017 Electric Rate Case — In October 2017, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately \$43 million. The request is based on a HTY ended June 30, 2017, a ROE of 10.25 percent, an equity ratio of 53.97 percent and a jurisdictional rate base of approximately \$885 million, including rate base additions through Nov. 30, 2017. This rate case also takes into account the decline in sales of 380 MW in 2017 from certain wholesale customers and seeks to adjust the life of SPS' Tolk power plant (Unit 1 from 2042 to 2032 and Unit 2 from 2045 to 2032).

Key dates in the procedural schedule are as follows:

- Staff and intervenor direct testimony — April 13, 2018;
- SPS' rebuttal testimony — May 2, 2018; and
- Hearings — May 15 - 25, 2018.

SPS anticipates a decision and implementation of final rates in the second half of 2018. As discussed above, the NMPRC has opened a docket on the impact of the TCJA, which may have a significant impact on this rate case.

Pending Regulatory Proceedings — FERC

MISO ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO TOs, including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, and the removal of ROE adders (including those for RTO membership), effective Nov. 12, 2013.

In December 2015, an ALJ recommended the FERC approve a base ROE of 10.32 percent for the MISO TOs. The ALJ found the existing 12.38 percent ROE to be unjust and unreasonable. The recommended 10.32 percent ROE applied a FERC ROE policy adopted in a June 2014 order (Opinion 531). The FERC approved the ALJ recommended 10.32 percent base ROE in an order issued in September 2016. This ROE would be applicable for Nov. 12, 2013 to Feb. 11, 2015, and prospectively from the date of the FERC order. The total prospective ROE would be 10.82 percent, including a 50 basis point adder for RTO membership. Various parties requested rehearing of the September 2016 order. The requests are pending FERC action.

In February 2015, a second complaint seeking to reduce the MISO ROE from 12.38 percent to 8.67 percent prior to any adder was filed with the FERC, resulting in a second period of potential refund from Feb. 12, 2015 to May 11, 2016. In June 2016, the ALJ recommended a ROE of 9.7 percent, applying the methodology adopted by the FERC in Opinion 531. In April 2017, the D.C. Circuit vacated and remanded Opinion 531. It is unclear how the D.C. Circuit's opinion to vacate and remand Opinion 531 will affect the September 2016 FERC order or the timing and outcome of the second ROE complaint. In September 2017, certain MISO TOs (not including NSP-Minnesota and NSP-Wisconsin) filed a motion to dismiss the second ROE complaint. The motion to dismiss is pending FERC action.

As of Dec. 31, 2017, NSP-Minnesota has processed the refunds for the Nov. 12, 2013 to Feb. 11, 2015 complaint period based on the 10.32 percent ROE. NSP-Minnesota has also recognized a current refund liability consistent with the best estimate of the final ROE for the Feb. 12, 2015 to May 11, 2016 complaint period.

SPP OATT Upgrade Costs — Under the SPP OATT, costs of participant-funded, or "sponsored," transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. The SPP OATT has allowed SPP to charge for these upgrades since 2008, but SPP had not been charging its customers for these upgrades. In 2016, the FERC granted SPP's request to recover the charges not billed since 2008. SPP subsequently billed SPS approximately \$13 million for these charges. SPP is also billing SPS ongoing charges of approximately \$0.5 million per month. SPS is currently seeking recovery of these SPP charges in its pending Texas and New Mexico base rate cases.

In October 2017, SPS filed a complaint against SPP regarding the amounts billed asserting that SPP has assessed upgrade charges to SPS even where SPS' transmission service was not dependent upon the upgrade as required by the SPP OATT. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the differential in future rate proceedings.

13. Commitments and Contingencies

Commitments

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

NSP-Minnesota Upper Midwest Wind Projects — NSP-Minnesota has gained approval to build and own 1,150 MW of new wind generation in the Upper Midwest. NSP-Minnesota is also seeking approval from the MPUC to build and own the Dakota Range project, a 300 MW wind project in South Dakota.

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

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

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

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

SPS Transmission NTC — SPS has accepted NTCs for several hundred miles of transmission line and related substation projects based on needs identified through SPP's various planning processes, including those associated with economics, reliability, generator interconnection and the load addition processes. Most significant are the 345 KV transmission line from TUCO to Yoakum County to Hobbs Plant and the Hobbs Plant to China Draw 345 KV transmission lines.

SPS New Mexico and Texas Wind Projects — SPS is seeking approval from the NMPRC and the PUCT to build, own and operate 1,000 MW of new wind generation through the addition of two wind generation facilities in New Mexico and Texas.

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

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

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2018.....	\$ 655	\$ 61	\$ 391	\$ 263
2019.....	255	118	288	251
2020.....	146	34	277	237
2021.....	59	85	280	227
2022.....	59	66	127	217
Thereafter	186	379	57	1,046
Total	<u>\$ 1,360</u>	<u>\$ 743</u>	<u>\$ 1,420</u>	<u>\$ 2,241</u>

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

PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the IPPs meeting contract obligations, including plant availability requirements. Contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of \$168 million, \$191 million and \$231 million in 2017, 2016 and 2015, respectively. At Dec. 31, 2017, 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, are as follows:

(Millions of Dollars)	Capacity	Energy ^(a)
2018	\$ 133	\$ 93
2019	87	99
2020	68	105
2021	73	140
2022	77	155
Thereafter	205	368
Total	<u>\$ 643</u>	<u>\$ 960</u>

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

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

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

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

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had \$124 million and \$127 million of capital lease obligations as of Dec. 31, 2017 and 2016, respectively. Xcel Energy Inc. eliminates 50 percent of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Gas storage facilities	\$ 201	\$ 201
Gas pipeline	21	21
Property held under capital leases	222	222
Accumulated depreciation	(71)	(66)
Total property held under capital leases, net	<u>\$ 151</u>	<u>\$ 156</u>

The remainder of the leases, primarily for office space, railcars, generating facilities, natural gas pipeline transportation, vehicles, aircraft and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations for Xcel Energy were approximately \$246 million, \$255 million and \$265 million for 2017, 2016 and 2015, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of \$210 million, \$216 million and \$224 million in 2017, 2016 and 2015, respectively, recorded to electric fuel and purchased power expenses.

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

(Millions of Dollars)	Operating Leases	PPA ^{(a) (b)} Operating Leases	Total Operating Leases	Capital Leases
2018	\$ 25	\$ 213	\$ 238	\$ 15
2019	30	230	260	14
2020	24	244	268	14
2021	24	246	270	14
2022	22	235	257	12
Thereafter	148	1,682	1,830	233
Total minimum obligation				302
Interest component of obligation				(213)
Present value of minimum obligation				<u>\$ 89</u> ^(c)

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

(b) PPA operating leases contractually expire through 2039.

(c) Future commitments exclude certain amounts related to Xcel Energy's 50 percent ownership interest in WYCO.

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

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse natural gas or biomass 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. In addition, certain solar PPAs provide the utility subsidiaries with 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 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 has been, or is required to be provided other than contractual payments for energy and capacity set forth in the PPAs.

Xcel Energy has 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 has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Xcel Energy's utility subsidiaries had approximately 3,537 MW of capacity under long-term PPAs at both Dec. 31, 2017 and 2016 with entities that have been determined to be VIEs. These agreements have expiration dates through the year 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk electric generating stations from TUCO under contracts for those facilities 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.

No significant financial support has been, or is required to be provided to TUCO by SPS, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of certain fuel procurement costs. SPS has determined that TUCO is a VIE. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing limited 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 consistently align with the partners' proportional equity ownership. Xcel Energy Inc. has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements.

Equity financing for these entities has been provided by Eloigne, NSP-Wisconsin and the general partner of each limited partnership. Xcel Energy's risk of loss 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. Obligations of the limited partnerships are generally secured by the housing properties of each limited partnership, and the creditors of each limited partnership have no significant recourse to Xcel Energy Inc. or its subsidiaries. Likewise, the assets of the limited partnerships may only be used to settle obligations of the limited partnerships, and not those of Xcel Energy Inc. or its subsidiaries.

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Current assets	\$ 6	\$ 7
Property, plant and equipment, net.	46	50
Other noncurrent assets	1	1
Total assets.	<u>\$ 53</u>	<u>\$ 58</u>
Current liabilities	\$ 9	\$ 8
Mortgages and other long-term debt payable.	26	30
Other noncurrent liabilities.	1	1
Total liabilities	<u>\$ 36</u>	<u>\$ 39</u>

Technology Agreements — Xcel Energy has a contract that extends through December 2022 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50 percent of the contract value for early termination. Xcel Energy capitalized or expensed \$98 million, \$119 million and \$109 million associated with the IBM contract in 2017, 2016 and 2015, 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 \$16 million, \$35 million and \$17 million associated with the Accenture contract in 2017, 2016 and 2015, respectively.

Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2018	\$ 26	\$ 11
2019	26	11
2020	8	11
2021	8	—
2022	3	—
Thereafter	—	—

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide 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. and its subsidiaries limit the exposure to a maximum stated amount. As of Dec. 31, 2017 and 2016, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and Surety Bonds

The following table presents guarantees and bond indemnities issued and outstanding as of Dec. 31, 2017:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of customer loans for the Farm Rewiring Program ^(a)	NSP-Wisconsin	\$ 1.0	\$ —	(f)
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases ^(b)	Xcel Energy Inc.	12.0	—	(g)
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement ^(c)	NSP-Minnesota	4.8	—	(h)
Guarantee of loan for Hiawatha Collegiate High School ^(d)	Xcel Energy Inc.	1.0	—	(g)
Total guarantees issued		\$ 18.8	\$ —	
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries ^(e)	Xcel Energy Inc.	\$ 53.1	(j)	(i)

- (a) The term of this guarantee expires in 2020, which is the final scheduled repayment date for the loans. As of Dec. 31, 2017, no claims had been made by the lender.
- (b) The terms of this guarantee expires in 2021 and 2023 when the associated leases expire.
- (c) The term of this guarantee expires in 2019 when the associated lease expires.
- (d) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.
- (e) 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.
- (f) The debtor becomes the subject of bankruptcy or other insolvency proceedings.
- (g) Nonperformance and/or nonpayment.
- (h) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.
- (i) Failure of any one of Xcel Energy Inc.'s utility subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy Inc. and the various surety companies, the surety companies have the discretion to demand that collateral be posted.
- (j) 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. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Environmental Contingencies

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

Site Remediation — Various federal and state environmental laws impose liability, without regard to the legality of the original conduct, where hazardous substances or other regulated materials have been released to the environment. 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 operated by Xcel Energy Inc.'s subsidiaries or their predecessors, or other entities; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to be a PRP that sent wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin was named a PRP for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Site) includes NSP-Wisconsin property, previously operated as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park); and an area of Lake Superior's Chequamegon Bay adjoining the park.

In 2012, NSP-Wisconsin agreed to remediate the Phase I Project Area (which includes the Upper Bluff and Kreher Park areas of the Site), under a settlement agreement with the EPA. In January 2017, NSP-Wisconsin agreed to remediate the Phase II Project Area (the Sediments), under a settlement agreement with the EPA. The settlement agreements were approved by the U.S. District Court for the Western District of Wisconsin. NSP-Wisconsin initiated a full scale wet dredge remedy of the Sediments in 2017. Going forward, NSP-Wisconsin anticipates completion of restoration activities of the Sediments in 2018 with finalization of Phase I Project Area construction and restoration activities in 2019. Groundwater treatment activities at the Site will continue.

The current cost estimate for the entire site (both Phase I Project Area and the Sediments) is approximately \$168 million, of which approximately \$138 million has been spent. As of Dec. 31, 2017 and 2016, NSP-Wisconsin had recorded a total liability of \$30 million and \$64 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation costs incurred at the Site. In 2012, the PSCW agreed to allow NSP-Wisconsin to pre-collect certain costs, to amortize costs over a ten-year period and to apply a three percent carrying cost to the unamortized regulatory asset. In December 2017, the PSCW approved an NSP-Wisconsin natural gas rate case, which included recovery of additional expenses associated with remediating the Site. The annual recovery of MGP clean-up costs will increase from \$12 million in 2017 to \$18 million in 2018.

Fargo, N.D. MGP Site — In May 2015, underground pipes, tars and impacted soils were discovered in a right-of-way in Fargo, N.D. that appeared to be associated with a former MGP operated by NSP-Minnesota or prior companies. NSP-Minnesota removed impacted soils and other materials and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). The North Dakota Department of Health approved NSP-Minnesota's proposed cleanup plan in January 2017, which involves targeted source removal of impacted soils and historic MGP infrastructure. It is anticipated that remediation activities will be performed in 2018. NSP-Minnesota has also initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota agreed to the parties' request for a stay of the litigation until May 31, 2018.

NSP-Minnesota had recorded an estimated liability of \$16 million as of Dec. 31, 2017, and \$11 million as of Dec. 31, 2016, for the Fargo MGP Site. The current cost estimate for the remediation of the site is approximately \$23 million, of which approximately \$7 million has been spent. NSP-Minnesota has deferred Fargo MGP Site costs allocable to the North Dakota jurisdiction, or approximately 88 percent of all remediation costs, as approved by the NDPSC. In December 2017, NSP-Minnesota filed a request with the MPUC to defer post-2017 expenditures allocable to the Minnesota jurisdiction.

Other MGP, Landfill or Disposal Sites — Xcel Energy is currently involved in investigating and/or remediating several MGP, landfill or other disposal sites. Xcel Energy has identified twelve sites across its service territories in addition to the sites in Ashland and Fargo, where contamination is present and where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities that are underway. Xcel Energy anticipates that these investigation or remediation activities will continue through at least 2018. Xcel Energy had accrued \$4 million as of Dec. 31, 2017 and \$2 million as of Dec. 31, 2016 for all of these sites. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. Xcel Energy anticipates that any amounts spent will be fully recovered from customers.

Environmental Requirements

Water and Waste

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

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the EPA published a final rule regulating the management, storage, and disposal of coal combustion residuals (CCRs) as a nonhazardous waste (CCR Rule). Industry and environmental non-governmental organizations sought judicial review of the final CCR Rule, but a final decision has not been issued in that litigation. The EPA announced in late 2017 its intent to revise the CCR Rule. It is anticipated that the EPA will publish the revised rule in the first quarter of 2018.

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

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

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

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

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

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). For Xcel Energy, these requirements will primarily impact plants at NSP-Minnesota. Xcel Energy estimates the likely cost for complying with impingement requirements may be incurred between 2018 and 2027 and is approximately \$41 million with the majority needed for NSP-Minnesota. Xcel Energy believes at least six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce entrainment. The exact total cost of the entrainment improvements is uncertain, but could be up to \$192 million. Xcel Energy anticipates these costs will be fully recoverable in rates.

Air

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

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

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

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

CSAPR — CSAPR addresses long range transport of PM and ozone by requiring reductions in SO₂ and NO_x from utilities in the eastern half of the United States using an emissions trading program. For Xcel Energy, the rule applies in Minnesota, Wisconsin and Texas.

CSAPR was adopted to address interstate emissions impacting downwind states' attainment of the ozone and particulate NAAQS. As the EPA revises NAAQS, it will consider whether to make any further reductions to CSAPR emission budgets and whether to change which states are included in the emissions trading program.

In September 2017, the EPA adopted a final rule that withdraws Texas from the CSAPR particle program and determines that further emission reductions in Texas are not needed to address interstate particle transport. Texas is no longer subject to the annual SO₂ and NO_x emission budgets under CSAPR. In November 2017, the National Parks Conservation Association and Sierra Club appealed this rule to the D.C. Circuit Court. In January 2018, the Court granted SPS' motion to intervene in support of the EPA's final rule.

Regional Haze Rules — The regional haze program requires SO₂, NO_x and PM emission controls at power plants and other industrial facilities to reduce visibility impairment in national parks and wilderness areas. The program is divided into two parts: BART and reasonable further progress. The requirements of the first regional haze plans developed by Minnesota and Colorado that apply to NSP-Minnesota and PSCo have been fully approved and implemented. Texas' first regional haze plan has undergone federal review as described below.

BART Determination for Texas: The EPA published a proposed BART rule for Texas in January 2017 that could have required installation of dry scrubbers to reduce SO₂ emissions from Harrington Units 1 and 2. Investment costs associated with dry scrubbers for Harrington Units 1 and 2 could have been approximately \$400 million. In October 2017, the EPA issued a revised final rule adopting a BART alternative Texas only SO₂ trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO₂ emissions from units in 2019 and future years. The anticipated costs of compliance are not expected to have a material impact on the results of operations, financial position or cash flows; 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 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 matter is now submitted to the court.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's October 2017 final BART rule to the Fifth Circuit, and filed a petition for administrative reconsideration of the final rule with the EPA. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule.

Reasonable Progress Rule: In January 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 SO₂ 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 approximately \$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 SO₂ emission reductions beyond those required in the BART alternative rule are needed at Tolk under the "reasonable progress" requirements of the regional haze program. The risk of these controls being imposed along with the risk of investments to provide additional cooling water to Tolk have caused SPS to seek to decrease the remaining depreciable life of the Tolk units. The EPA has not announced a schedule for acting on the remanded rule.

Implementation of the NAAQS for SO₂ — The EPA adopted a more stringent NAAQS for SO₂ in 2010, and evaluated areas in three phases. In December 2017, the EPA adopted a final rule that completed its initial designations of areas attaining or not attaining the standard. The EPA's final actions designate all areas near Xcel Energy's generating plants as meeting the SO₂ NAAQS with two exceptions. In June 2016, the EPA issued final designations which found the areas near the SPS Harrington and PSCo Pawnee plants 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. Since the 2016 "unclassifiable" designation, the Colorado Department of Public Health and Environment has prepared and submitted air dispersion modeling to the EPA demonstrating that the area near the Pawnee plant meets the SO₂ NAAQS. The EPA has not yet completed its evaluation of the Pawnee plant.

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, which would be due by 2022, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO₂ 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 SO₂ control systems be required or require upgrades 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 position or cash flows.

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

Asset Retirement Obligations

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

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

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 14 for further discussion of nuclear obligations.

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

(Millions of Dollars)	Beginning Balance Jan. 1, 2017	Liabilities Recognized	Liabilities Settled ^(a)	Accretion	Cash Flow Revisions ^(b)	Ending Balance Dec. 31, 2017
Electric plant						
Nuclear production decommissioning	\$ 2,249	\$ —	\$ —	\$ 114	\$ (489)	\$ 1,874
Steam and other production ash containment	117	—	(16)	5	9	115
Wind production	92	—	—	4	—	96
Steam, hydro and other production asbestos .	88	1	(13)	4	(3)	77
Electric distribution	20	—	—	1	—	21
Other	5	—	—	—	—	5
Natural gas plant						
Gas transmission and distribution	205	—	—	8	69	282
Other	4	—	—	—	—	4
Common and other property						
Common general plant asbestos	1	—	(1)	—	—	—
Common miscellaneous	1	—	—	—	—	1
Total liability	<u>\$ 2,782</u>	<u>\$ 1</u>	<u>\$ (30)</u>	<u>\$ 136</u>	<u>\$ (414)</u>	<u>\$ 2,475</u>

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

(b) In 2017, AROs were revised for changes in estimated cash flows and the timing of those cash flows. The nuclear decommissioning ARO decreased due to updated assumptions in the nuclear triennial filing. Changes in the gas transmission and distribution AROs were mainly related to increased labor costs.

The aggregate fair value of NSP-Minnesota’s legally restricted assets, for purposes of funding future nuclear decommissioning, was \$2.1 billion as of Dec. 31, 2017, consisting of external investment funds.

(Millions of Dollars)	Beginning Balance Jan. 1, 2016	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions ^(b)	Ending Balance Dec. 31, 2016
Electric plant						
Nuclear production decommissioning	\$ 2,141	\$ —	\$ —	\$ 108	\$ —	\$ 2,249
Steam and other production ash containment	132	—	(6)	5	(14)	117
Steam, hydro and other production asbestos	84	—	—	4	—	88
Wind production	72	17 ^(a)	—	3	—	92
Electric distribution	13	—	—	1	6	20
Other	4	1	—	—	—	5
Natural gas plant						
Gas transmission and distribution	156	—	—	7	42	205
Other	4	—	—	—	—	4
Common and other property						
Common general plant asbestos	1	—	—	—	—	1
Common miscellaneous	2	—	—	—	(1)	1
Total liability	<u>\$ 2,609</u>	<u>\$ 18</u>	<u>\$ (6)</u>	<u>\$ 128</u>	<u>\$ 33</u>	<u>\$ 2,782</u>

(a) The liability recognized relates to the NSP-Minnesota Courtenay Wind Farm which was placed in service during 2016.

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

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.9 billion as of Dec. 31, 2016, consisting of external investment funds.

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

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of generation, transmission and distribution facilities of its utility subsidiaries that are recovered currently in rates. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long time periods over which the amounts were accrued and the changing of rates over time, 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.

The accumulated balances by entity were as follows at Dec. 31:

(Millions of Dollars)	2017	2016
NSP-Minnesota	\$ 442	\$ 419
PSCo.	346	367
SPS	197	209
NSP-Wisconsin	146	140
Total Xcel Energy	<u>\$ 1,131</u>	<u>\$ 1,135</u>

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$13.4 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 \$13.0 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear incident. NSP-Minnesota is subject to assessments of up to \$127 million per reactor-incident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$19 million per reactor per incident during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL) and European Mutual Association for Nuclear Insurance (EMANI). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain 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. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$19 million for business interruption insurance and \$41 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

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

Employment, Tort and Commercial Litigation

Gas Trading Litigation — e prime inc. (e prime) is a wholly owned subsidiary of Xcel Energy Inc. 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. Thirteen lawsuits were commenced against e prime and Xcel Energy (and NSP-Wisconsin, in two instances) between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices.

e prime, Xcel Energy Inc. and its other affiliates were sued along with several other gas marketing companies. These cases were all consolidated in the U.S. District Court in Nevada. Six of the cases remain active, which includes a multi-district litigation (MDL) matter consisting of a Colorado class (Breckenridge), a Wisconsin class (Arandell Corp.), a Missouri class, a Kansas class, and two other cases identified as "Sinclair Oil" and "Farmland." In March 2017, summary judgment was granted by the MDL judge in favor of Xcel Energy and e prime in the Sinclair Oil and Farmland cases. In November 2017, the U.S. District Court in Nevada granted summary judgment against two plaintiffs in the Arandell Corp. case in favor of Xcel Energy and NSP-Wisconsin, leaving only three individual plaintiffs remaining in the litigation. In addition, the plaintiffs' motions for class certification and remand back to originating courts in these cases were denied in March 2017. Plaintiffs have appealed the summary judgment motions granted in the Farmland and Sinclair Oil cases and the denial of class certification and remand to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). Oral arguments were heard before the Ninth Circuit in February 2018. A final decision is expected by the end of the first quarter of 2019. Xcel Energy, NSP-Wisconsin and e prime have concluded that a loss is remote.

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

In January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so. This claim is substantially similar to the arguments previously raised by DRC. Dates for this proceeding have not been scheduled.

PSCo has concluded that a loss is remote with respect to both of these matters as the service agreements were developed to implement CPUC approved tariffs and PSCo has complied with the tariff provisions. Also, if a loss were sustained, PSCo believes it would be allowed to recover these costs through traditional regulatory mechanisms. The amount or range in dispute is presently unknown and no accrual has been recorded for this matter.

Other Contingencies

See Note 12 for further discussion.

14. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or 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 has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero. There were no DOE fuel disposal assessments in 2017 or 2016.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 16 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks.

Regulatory Plant Decommissioning Recovery — Decommissioning activities related to 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. The MPUC most recently approved NSP-Minnesota's 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota's most recently approved decommissioning study resulted in an annual funding requirement of \$14 million to be recovered in utility customer rates which started in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2017, NSP-Minnesota has accumulated \$2.1 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

(Millions of Dollars)	Regulatory Basis	
	2017	2016
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars) . . .	\$ 3,012	\$ 3,012
Effect of escalating costs (to 2017 and 2016 dollars, respectively, at 4.36/3.36 percent)	396	258
Estimated decommissioning cost obligation (in current dollars)	3,408	3,270
Effect of escalating costs to payment date (4.36/3.36 percent)	7,797	7,935
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 2.80 percent and 3.25 percent for 2017 and 2016, respectively)	(6,398)	(7,068)
Discounted decommissioning cost obligation	<u>\$ 4,807</u>	<u>\$ 4,137</u>
Assets held in external decommissioning trust	\$ 2,143	\$ 1,861
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,664	2,276

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. The 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. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	2017	2016
Discounted decommissioning cost obligation - regulated basis	\$ 4,807	\$ 4,137
Differences in discount rate and market risk premium	(1,403)	(1,044)
O&M costs not included for GAAP	(1,041)	(844)
ARO differences between 2017 and 2014 cost studies	(489)	—
Nuclear production decommissioning ARO - GAAP	<u>\$ 1,874</u>	<u>\$ 2,249</u>

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Millions of Dollars)	2017	2016	2015
Annual decommissioning recorded as depreciation expense: ^(a) ^(b)	\$ 20	\$ 20	\$ 7

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

(b) Decommissioning expenses in 2017 and 2016 include Minnesota's retail jurisdiction annual funding requirement of approximately \$14 million. The 2015 expense was offset by the DOE settlement refund.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation for both 2017 and 2016. The most recent triennial filing was submitted in December 2017 and is currently pending with the MPUC, with an order expected in 2018.

15. Regulatory Assets and Liabilities

Xcel Energy prepares its consolidated financial statements in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of regulatory accounting guidance under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

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

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2017		Dec. 31, 2016	
			Current	Noncurrent	Current	Noncurrent
Regulatory Assets						
Pension and retiree medical obligations ^(a)	9	Various	\$ 91	\$ 1,499	\$ 89	\$ 1,549
Net AROs ^(b)	1, 13, 14	Plant lives	—	301	—	379
Excess deferred taxes - TCJA	6	Various	—	254	—	—
Recoverable deferred taxes on AFUDC recorded in plant ^(c)	1	Plant lives	—	244	—	424
Environmental remediation costs	1, 13	Various	16	165	11	165
Contract valuation adjustments ^(d)	1, 11	Term of related contract	21	93	18	111
Depreciation differences	1	One to fourteen years	20	69	15	90
Purchased power contract costs	13	Term of related contract	3	67	2	70
PI EPU	12	Seventeen years	3	58	3	62
Losses on reacquired debt	4	Term of related debt	5	48	4	23
Conservation programs ^(e)	1	One to two years	50	32	48	48
State commission adjustments	1	Plant lives	1	29	1	27
Property tax		Various	8	24	9	2
Nuclear refueling outage costs	1	One to two years	49	20	49	16
Deferred purchased natural gas and electric energy costs	1	Various	21	13	18	16
Sales true up and revenue decoupling		One to two years	37	12	—	—
Gas pipeline inspection and remediation costs	12	One to two years	24	12	7	14
Renewable resources and environmental initiatives	13	One to three years	48	10	34	23
Other		Various	27	55	56	62
Total regulatory assets			\$ 424	\$ 3,005	\$ 364	\$ 3,081

- (a) Includes \$179 million and \$241 million for the regulatory recognition of the NSP-Minnesota pension expense, of which \$9 million and \$15 million is included in the current asset at Dec. 31, 2017 and 2016, respectively. Also included are \$8 million and \$11 million of regulatory assets related to the nonqualified pension plan, of which \$1 million and \$3 million is included in the current asset at Dec. 31, 2017 and 2016, respectively.
- (b) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
- (c) Includes a write-down of \$202 million as a result of the revaluation of deferred tax gross up at the new federal tax rate at Dec. 31, 2017.
- (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.

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

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2017		Dec. 31, 2016	
			Current	Noncurrent	Current	Noncurrent
Regulatory Liabilities						
Excess deferred taxes - TCJA ^(a)	6	Various	\$ —	\$ 3,733	\$ —	\$ —
Plant removal costs	1, 13	Plant lives	—	1,131	—	1,135
Renewable resources and environmental initiatives	12, 13	Various	19	56	5	71
ITC deferrals	1, 6	Various	—	42	—	45
Deferred income tax adjustment	1, 6	Various	—	38	—	48
Deferred electric, natural gas and steam production costs	1	Less than one year	104	—	98	—
Contract valuation adjustments ^(b)	1, 11	Term of related contract	30	—	22	2
Conservation programs ^(c)	1, 12	Less than one year	23	—	25	—
DOE settlement		Less than one year	18	—	20	—
Other		Various	45	83	51	82
Total regulatory liabilities ^(d)			\$ 239	\$ 5,083	\$ 221	\$ 1,383

- (a) Primarily relates to the revaluation of recoverable/regulated plant ADIT and \$174 million revaluation impact of non-plant ADIT at Dec. 31, 2017.
- (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.
- (d) Revenue subject to refund of \$15 million and \$46 million for 2017 and 2016, respectively, is included in other current liabilities.

At Dec. 31, 2017 and 2016, approximately \$250 million and \$166 million of Xcel Energy's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes recoverable purchased natural gas and electric energy costs and certain expenditures associated with pension and renewable resources and environmental initiatives.

16. Other Comprehensive Income

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

(Millions of Dollars)	Year Ended Dec. 31, 2017		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	\$ (51)	\$ (59)	\$ (110)
Other comprehensive loss before reclassifications	—	(3)	(3)
Losses reclassified from net accumulated other comprehensive loss	3	7	10
Net current period other comprehensive income	3	4	7
Adoption of ASU No. 2018-02 ^(a)	(10)	(12)	(22)
Accumulated other comprehensive loss at Dec. 31	<u>\$ (58)</u>	<u>\$ (67)</u>	<u>\$ (125)</u>

^(a) In 2017, Xcel Energy implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings. For further information, see Note 2.

(Millions of Dollars)	Year Ended Dec. 31, 2016		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	\$ (55)	\$ (55)	\$ (110)
Other comprehensive loss before reclassifications	—	(8)	(8)
Losses reclassified from net accumulated other comprehensive loss	4	4	8
Net current period other comprehensive income (loss)	4	(4)	—
Accumulated other comprehensive loss at Dec. 31	<u>\$ (51)</u>	<u>\$ (59)</u>	<u>\$ (110)</u>

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

(Millions of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Losses (gains) on cash flow hedges:		
Interest rate derivatives	\$ 5 ^(a)	\$ 6 ^(a)
Total, pre-tax	5	6
Tax benefit	(2)	(2)
Total, net of tax	3	4
Defined benefit pension and postretirement losses (gains):		
Amortization of net losses	12 ^(b)	6 ^(b)
Total, pre-tax	12	6
Tax benefit	(5)	(2)
Total, net of tax	7	4
Total amounts reclassified, net of tax	<u>\$ 10</u>	<u>\$ 8</u>

^(a) Included in interest charges.

^(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 9 for detail regarding these benefit plans.

17. Segments and Related Information

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 are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

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

- Xcel Energy's 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. Regulated electric utility also includes wholesale commodity and trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility 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 \$140 million and \$133 million as of Dec. 31, 2017 and 2016, 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 because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

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

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

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2017					
Operating revenues from external customers	\$ 9,676	\$ 1,650	\$ 78	\$ —	\$ 11,404
Intersegment revenues	2	1	—	(3)	—
Total revenues	<u>\$ 9,678</u>	<u>\$ 1,651</u>	<u>\$ 78</u>	<u>\$ (3)</u>	<u>\$ 11,404</u>
Depreciation and amortization	\$ 1,298	\$ 174	\$ 7	\$ —	\$ 1,479
Interest charges and financing costs	449	57	122	—	628
Income tax expense (benefit).	528	23	(9)	—	542
Net income (loss).	1,066	182	(100)	—	1,148
2016					
Operating revenues from external customers	\$ 9,500	\$ 1,531	\$ 76	\$ —	\$ 11,107
Intersegment revenues	1	1	—	(2)	—
Total revenues	<u>\$ 9,501</u>	<u>\$ 1,532</u>	<u>\$ 76</u>	<u>\$ (2)</u>	<u>\$ 11,107</u>
Depreciation and amortization	\$ 1,136	\$ 160	\$ 7	\$ —	\$ 1,303
Interest charges and financing costs	450	54	116	—	620
Income tax expense (benefit).	567	76	(62)	—	581
Net income (loss).	1,067	124	(68)	—	1,123

(Millions of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2015					
Operating revenues from external customers	\$ 9,276	\$ 1,672	\$ 76	\$ —	\$ 11,024
Intersegment revenues	2	1	—	(3)	—
Total revenues	<u>\$ 9,278</u>	<u>\$ 1,673</u>	<u>\$ 76</u>	<u>\$ (3)</u>	<u>\$ 11,024</u>
Depreciation and amortization	\$ 963	\$ 155	\$ 6	\$ —	\$ 1,124
Interest charges and financing costs	426	50	93	—	569
Income tax expense (benefit)	509	60	(26)	—	543
Net income (loss)	921	106	(43)	—	984

18. Summarized Quarterly Financial Data (Unaudited)

(Amounts in millions, except per share data)	Quarter Ended			
	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017
Operating revenues	\$ 2,946	\$ 2,645	\$ 3,017	\$ 2,796
Operating income	486	460	818	426
Net income	239	227	492	189
EPS total — basic	\$ 0.47	\$ 0.45	\$ 0.97	\$ 0.37
EPS total — diluted	0.47	0.45	0.97	0.37
Cash dividends declared per common share	0.36	0.36	0.36	0.36

(Amounts in millions, except per share data)	Quarter Ended			
	March 31, 2016	June 30, 2016	Sept. 30, 2016	Dec. 31, 2016
Operating revenues	\$ 2,772	\$ 2,500	\$ 3,040	\$ 2,795
Operating income	490	432	827	465
Net income	241	197	458	227
EPS total — basic	\$ 0.47	\$ 0.39	\$ 0.90	\$ 0.45
EPS total — diluted	0.47	0.39	0.90	0.45
Cash dividends declared per common share	0.34	0.34	0.34	0.34

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

None.

Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2017, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

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

Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2017 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

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

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 2018 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2018 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 2018 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 2018 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2018 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, 2017.
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, 2017, 2016, and 2015.
Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2017, 2016, and 2015.
Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2017, 2016, and 2015.
Consolidated Balance Sheets — As of Dec. 31, 2017 and 2016.
Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2017, 2016, and 2015.
Consolidated Statements of Capitalization — As of Dec. 31, 2017 and 2016.
 2. Schedule I — Condensed Financial Information of Registrant.
Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2017, 2016 and 2015.
 3. Exhibits
- * Indicates incorporation by reference
- + Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

- 3.01* Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 18, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
- 3.02* Bylaws of Xcel Energy Inc., as amended on Feb. 17, 2016 (Exhibit 3.01 to Form 8-K dated Feb. 18, 2016 (file no. 001-03034)).

Xcel Energy Inc.

- 4.01* Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 14, 2000).
- 4.02* Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$300 million principal amount of 6.5 percent Senior Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).
- 4.03* Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
- 4.04* Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
- 4.05* Supplemental Indenture No. 5 dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$550 million principal amount of 4.70 percent Senior Notes, Series due May 15, 2020 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated May 10, 2010).
- 4.06* Supplemental Indenture No. 6 dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$250 million principal amount of 4.80 percent Senior Notes, Series due Sept. 15, 2041 (Exhibit 4.01 to Form 8-K dated Sept. 12, 2011 (file no. 001-03034)).
- 4.07* Supplemental Indenture No. 8 dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$250 million aggregate principal amount of 1.20 percent Senior Notes, Series due June 1, 2017 and \$250 million aggregate principal amount of 3.30 percent Senior Notes, Series due June 1, 2025. (Exhibit 4.01 to Form 8-K dated June 1, 2015 (file no. 001-03034)).
- 4.08* Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, with respect to \$400 million aggregate principal amount of 2.40 percent Senior Notes, Series due March 15, 2021 (Exhibit 4.02 to Form 8-K dated March 8, 2016 (file no. 001-03034)).

- 4.09* Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating \$300.0 million in aggregate principal amount of 2.60 percent Senior Notes, Series due March 15, 2022 and \$500.0 million aggregate principal amount of 3.35 percent Senior Notes, Series due Dec. 1, 2026 (Exhibit 4.01 to Form 8-K dated Dec. 1, 2016 (file no. 001-03034)).

NSP-Minnesota

- 4.10* 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, dated as follows:
- 4.11* Supplemental Trust Indenture dated June 1, 1995, creating \$250 million principal amount of 7.125 percent First Mortgage Bonds, Series due July 1, 2025.
- 4.12* Supplemental Trust Indenture dated March 1, 1998, creating \$150 million principal amount of 6.5 percent First Mortgage Bonds, Series due March 1, 2028.
- 4.13* Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
- 4.14* Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities.
- 4.15* 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 (Assignment and Assumption of Indenture) (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
- 4.16* 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 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated July 14, 2005).
- 4.17* 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 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated May 18, 2006).
- 4.18* Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).
- 4.19* 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 percent First Mortgage Bonds, Series due Nov. 1, 2039 (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated Nov. 16, 2009).
- 4.20* 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 1.950 percent First Mortgage Bonds, Series due Aug. 15, 2015 and \$250 million principal amount of 4.850 percent First Mortgage Bonds, Series due Aug. 15, 2040 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 4, 2010 (file no. 001-31387)).
- 4.21* 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 percent First Mortgage Bonds, Series due Aug. 15, 2022 and \$500 million principal amount of 3.40 percent First Mortgage Bonds, Series due Aug. 15, 2042 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated Aug. 13, 2012 (file no. 001-31387)).
- 4.22* 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 percent First Mortgage Bonds, Series due May 15, 2023 (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 20, 2013 (file no. 001-31387)).
- 4.23* 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 percent First Mortgage Bonds, Series due May 15, 2044. (Exhibit 4.01 to NSP-Minnesota Form 8-K dated May 13, 2014 (file no. 001-31387)).
- 4.24* Supplemental Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$300 million principal amount of 2.20 percent First Mortgage Bonds, Series due Aug. 15, 2020 and \$300 million principal amount of 4.00 percent First Mortgage Bonds, Series due Aug. 15, 2045 (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Aug. 11, 2015 (file no. 001-31387)).

- 4.25* Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating \$350 million principal amount of 3.600 percent First Mortgage Bonds, Series due May 15, 2046. (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated May 31, 2016 (file no. 001-31387)).
- 4.26* Supplemental 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 percent First Mortgage Bonds, Series due Sept. 15, 2047. (Exhibit 4.01 to Form 8-K of NSP-Minnesota dated Sept. 13, 2017 (file no. 001-31387)).

NSP-Wisconsin

- 4.27* 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.
- 4.28* Trust Indenture dated Sept. 1, 2000, between NSP-Wisconsin and Firststar Bank, NA as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).
- 4.29* Supplemental Trust Indenture dated Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2003).
- 4.30* 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 percent First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Sept. 3, 2008 (file no. 001-03140)).
- 4.31* 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 3.700 percent First Mortgage Bonds, Series due Oct. 1, 2042 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Oct. 10, 2012 (file no. 001-03140)).
- 4.32* 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 percent First Mortgage Bonds, Series due June 15, 2024. (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated June 23, 2014 (file no. 001-03140)).
- 4.33* Supplemental Trust Indenture dated as of Nov. 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating \$100 million in aggregate principal amount of 3.75 percent First Mortgage Bonds, Series due Dec. 1, 2047. (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Dec. 4, 2017 (file no. 001-03140)).

PSCo

- 4.34* 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.
- 4.35* Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).
- 4.36* Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust National Association, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no. 001-03280) dated Aug. 8, 2007).
- 4.37* Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating \$300 million principal amount of 5.80 percent First Mortgage Bonds, Series No. 18 due 2018 and \$300 million principal amount of 6.50 percent First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).
- 4.38* Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating \$400 million principal amount of 5.125 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).
- 4.39* Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$400 million principal amount of 3.200 percent First Mortgage Bonds, Series No. 21 due 2020 (Exhibit 4.01 of Form 8-K of PSCo dated Nov. 8, 2010 (file no. 001-03280)).
- 4.40* Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250 million principal amount of 4.75 percent First Mortgage Bonds, Series No. 22 due 2041 (Exhibit 4.01 to Form 8-K of PSCo dated Aug. 9, 2011 (file no. 001-03280)).
- 4.41* Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$300 million principal amount of 2.25 percent First Mortgage Bonds, Series No. 23 due 2022 and \$500 million principal amount of 3.60 percent First Mortgage Bonds, Series No. 24 due 2042 (Exhibit 4.01 to PSCo's Form 8-K dated Sept. 11, 2012 (file no. 001-03280)).

- 4.42* Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250 million principal amount of 2.50 percent First Mortgage Bonds, Series No. 25 due 2023 and \$250 million principal amount of 3.95 percent First Mortgage Bonds, Series No. 26 due 2043 (Exhibit 4.01 to Form 8-K of PSCo dated March 26, 2013 (file no. 001-03280)).
- 4.43* Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$300 million principal amount of 4.30 percent First Mortgage Bonds, Series No. 27 due 2044. (Exhibit 4.01 to Form 8-K of PSCo dated March 10, 2014 (file no. 001-03280)).
- 4.44* Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250 million principal amount of 2.90 percent First Mortgage Bonds, Series No. 28 due 2025. (Exhibit 4.01 to Form 8-K of PSCo dated May 12, 2015 (file no. 001-03280)).
- 4.45* Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating \$250 million principal amount of 3.55 percent First Mortgage Bonds, Series No. 29 due 2046. (Exhibit 4.01 to Form 8-K of PSCo dated June 13, 2016 (file no. 001-03280)).
- 4.46* Supplemental Indenture No. 27 dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as Trustee, creating \$400 million principal amount of 3.80 percent First Mortgage Bonds, Series No. 30 due 2047. (Exhibit 4.01 to Form 8-K of PSCo dated June 19, 2017 (file no. 001-03280)).

SPS

- 4.47* Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
- 4.48* Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating \$100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2003).
- 4.49* Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).
- 4.50* Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee (Exhibit 4.01 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
- 4.51* 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 percent First Mortgage Bonds, Series No. 1 due 2041 (Exhibit 4.02 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
- 4.52* Sixth Supplemental Indenture dated as of June 1, 2014 between SPS and The Bank of New York Mellon Trust Company, N.A., as successor Trustee. (Exhibit 4.03 to SPS' Form 8-K dated June 2, 2014 (file no. 001-03789)).
- 4.53* Supplemental Indenture No. 3 dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating \$150 million principal amount of 3.30 percent First Mortgage Bonds, Series No. 3 due 2024. (Exhibit 4.02 to SPS' Form 8-K dated June 9, 2014 (file no. 001-03789)).
- 4.54* 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 percent First Mortgage Bonds, Series No. 4 due 2046. (Exhibit 4.02 to Form 8-K of SPS dated Aug. 12, 2016 (file no. 001-03789)).
- 4.55* 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 percent First Mortgage Bonds, Series No. 5 due 2047. (Exhibit 4.02 to Form 8-K of SPS dated Aug. 9, 2017 (file no. 001-03789)).

Xcel Energy Inc.

- 10.01*+ Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.02*+ Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.03*+ Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.04* Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).

- 10.05*+ Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.06*+ Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
- 10.07*+ Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
- 10.08*+ Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
- 10.09*+ Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
- 10.10*+ Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed April 5, 2011).
- 10.11*+ Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.07 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
- 10.12*+ First Amendment effective Nov. 29, 2011 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
- 10.13*+ Second Amendment dated Oct. 26, 2011 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.18 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2011).
- 10.14*+ First Amendment dated Feb. 20, 2013 to the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
- 10.15*+ Fourth Amendment dated Feb. 20, 2013 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.02 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended March 31, 2013).
- 10.16*+ First Amendment dated May 21, 2013 to the Xcel Energy Inc. 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (Exhibit 10.21 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
- 10.17*+ Second Amendment dated May 21, 2013 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.22 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
- 10.18*+ Xcel Energy Inc. 2005 Long-Term Incentive Plan Form of Long-Term Incentive Award Agreement (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2013).
- 10.19*+ Xcel Energy Inc. 2015 Omnibus Incentive Plan (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2015).
- 10.20*+ Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. (As First Effective May 20, 2015) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.02 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
- 10.21*+ Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan. (Exhibit 10.03 to Form 8-K of Xcel Energy, dated May 26, 2015 (file no. 001-03034).
- 10.22*+ Xcel Energy Inc. 2015 Omnibus Incentive Plan Form of Award Agreement (Exhibit 10.28 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2015).
- 10.23*+ Xcel Energy Inc. Executive Annual Incentive Award Sub-plan pursuant to the Xcel Energy Inc. 2015 Omnibus Incentive Plan (Exhibit 10.29 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2015).
- 10.24*+ Fifth Amendment dated May 3, 2016 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended June 30, 2016).
- 10.25* Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.01 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).

- 10.26*+ Third Amendment dated Sept. 30, 2016 to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.01 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2016).
- 10.27*+ Form of Xcel Energy, Inc. 2015 Omnibus Incentive Plan Award Agreement and Award Terms and Conditions (Restricted Stock Units and Performance Share Units) under the Xcel Energy Inc. 2015 Omnibus Incentive Plan (Exhibit 10.27 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2016).
- 10.28*+ Fourth Amendment to the Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (Exhibit 10.1 to Form 10-Q of Xcel Energy for the quarter ended Sept. 30, 2017 (file no. 001-03034)).
- 10.29* 364-Day Term Loan Agreement dated as of Dec. 5, 2017 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent (Exhibit 99.01 to Form 8-K of Xcel Energy dated Dec. 5, 2017 (file no. 001-03034)).
- 10.30*+ Sixth Amendment dated Feb. 22, 2018 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy.

NSP-Minnesota

- 10.31* Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
- 10.32* Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.02 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).

NSP-Wisconsin

- 10.33* Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
- 10.34* Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.05 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).

PSCo

- 10.35* Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 3, 2004).
- 10.36* Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.03 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).

SPS

- 10.37* Second Amended and Restated Credit Agreement, dated as of June 20, 2016 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agents. (Exhibit 99.04 to Form 8-K of Xcel Energy dated June 20, 2016 (file no. 001-03034)).

Xcel Energy Inc.

- 12.01 Statement of Computation of Ratio of Earnings to Fixed Charges.
- 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.
- 99.01 Statement pursuant to Private Securities Litigation Reform Act of 1995.
- 101 The following materials from Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2017 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Consolidated Statements of Capitalization, (vii) Notes to Consolidated Financial Statements, (viii) document and entity information, (ix) Schedule I, and (x) Schedule II.

SCHEDULE I

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

	Year Ended Dec. 31		
	2017	2016	2015
Income			
Equity earnings of subsidiaries	\$ 1,263	\$ 1,199	\$ 1,046
Total income	<u>1,263</u>	<u>1,199</u>	<u>1,046</u>
Expenses and other deductions			
Operating expenses	30	22	20
Other income	(6)	(3)	(1)
Interest charges and financing costs	128	116	91
Total expenses and other deductions	<u>152</u>	<u>135</u>	<u>110</u>
Income before income taxes	1,111	1,064	936
Income tax benefit	(37)	(59)	(48)
Net income	<u>\$ 1,148</u>	<u>\$ 1,123</u>	<u>\$ 984</u>
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of \$3, \$(3), and \$(3) respectively	\$ 4	\$ (4)	\$ (5)
Derivative instruments, net of tax of \$2, \$2, and \$2, respectively	3	4	3
Other comprehensive income (loss)	<u>7</u>	<u>—</u>	<u>(2)</u>
Comprehensive income	<u>\$ 1,155</u>	<u>\$ 1,123</u>	<u>\$ 982</u>
Weighted average common shares outstanding:			
Basic	509	509	508
Diluted	509	509	508
Earnings per average common share:			
Basic	\$ 2.26	\$ 2.21	\$ 1.94
Diluted	2.25	2.21	1.94
Cash dividends declared per common share	1.44	1.36	1.28

See Notes to Condensed Financial Statements

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

	Year Ended Dec. 31		
	2017	2016	2015
Operating activities			
Net cash provided by operating activities	\$ 1,208	\$ 817	\$ 705
Investing activities			
Capital contributions to subsidiaries	(849)	(414)	(820)
Investments in the utility money pool	(1,258)	(1,880)	(971)
Return of investments in the utility money pool	1,173	1,880	987
Net cash used in investing activities	(934)	(414)	(804)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	715	(516)	204
Proceeds from issuance of long-term debt	—	1,539	495
Repayment of long-term debt	(250)	(704)	—
Proceeds from issuance of common stock	—	—	7
Repurchase of common stock	(3)	(32)	—
Dividends paid	(721)	(681)	(607)
Other	(14)	(9)	(1)
Net cash (used in) provided by financing activities	(273)	(403)	98
Net change in cash and cash equivalents	1	—	(1)
Cash and cash equivalents at beginning of period	—	—	1
Cash and cash equivalents at end of period	<u>\$ 1</u>	<u>\$ —</u>	<u>\$ —</u>

See Notes to Condensed Financial Statements

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

	Dec. 31	
	2017	2016
Assets		
Cash and cash equivalents	\$ 1	\$ —
Accounts receivable from subsidiaries	302	364
Other current assets	1	10
Total current assets	304	374
Investment in subsidiaries	14,932	13,904
Other assets	103	163
Total other assets	15,035	14,067
Total assets	\$ 15,339	\$ 14,441
Liabilities and Equity		
Current portion of long-term debt	\$ —	\$ 250
Dividends payable	183	172
Short-term debt	783	68
Other current liabilities	11	18
Total current liabilities.	977	508
Other liabilities.	29	37
Total other liabilities	29	37
Commitments and contingencies		
Capitalization		
Long-term debt.	2,878	2,875
Common stockholders' equity	11,455	11,021
Total capitalization	14,333	13,896
Total liabilities and equity	\$ 15,339	\$ 14,441

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 OCI 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.

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

(Millions of Dollars)	2017		2016	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	\$ 68	\$ —	\$ 59	\$ —
NSP-Wisconsin	13	—	14	—
PSCo	69	—	132	—
SPS	26	—	31	—
Xcel Energy Services Inc.	95	—	93	—
Xcel Energy Ventures Inc.	14	—	17	—
Other subsidiaries of Xcel Energy Inc.	17	—	18	—
	\$ 302	\$ —	\$ 364	\$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were \$1,063 million, \$923 million and \$784 million for the years ended Dec. 31, 2017, 2016 and 2015, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — Xcel Energy received FERC approval 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. The following tables present money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2017
Loan outstanding at period end	85
Average loan outstanding	36
Maximum loan outstanding	85
Weighted average interest rate, computed on a daily basis	1.15%
Weighted average interest rate at end of period	1.18%
Money pool interest income	\$ 0.1

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016	Year Ended Dec. 31, 2015
Loan outstanding at period end.	85	—	—
Average loan outstanding	38	66	27
Maximum loan outstanding	226	211	141
Weighted average interest rate, computed on a daily basis	1.13%	0.69%	0.42%
Weighted average interest rate at end of period	1.18%	N/A	N/A
Money pool interest income	\$ 0.4	\$ 0.5	\$ 0.1

See Xcel Energy's notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

XCEL ENERGY INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2017, 2016 AND 2015
(amounts in millions)

	Balance at Jan. 1	Additions		Deductions from Reserves ^(b)	Balance at Dec. 31
		Charged to Costs and Expenses	Charged to Other Accounts ^(a)		
Allowance for bad debts:					
2017.....	\$ 51	\$ 39	\$ 10	\$ 48	\$ 52
2016.....	52	39	11	51	51
2015.....	58	36	12	54	52
NOL and tax credit valuation allowances:					
2017.....	\$ 58	\$ 9	\$ 22	\$ 12	\$ 77
2016.....	28	3	35	8	58
2015.....	3	2	25	2	28

^(a) Accrual of valuation allowance for North Dakota ITC, offset to regulatory liability.

^(b) Reductions to valuation allowances for North Dakota ITC carryforwards primarily due to a consolidated adjustment to the regulatory liability accrual referenced above. Reductions to valuation allowances for NOL carryforwards primarily due to changes in forecasted taxable income.

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. 23, 2018

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)

* _____
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

Headquarters

414 Nicollet Mall, Minneapolis, MN 55401

Website

xcelenergy.com

Stock Transfer Agent

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 Annual 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 Listing 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 2017.

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.

Xcel Energy joins Nasdaq

Xcel Energy Inc. common stock began trading on the Nasdaq Global Select Market (Nasdaq) in 2018 after the company voluntarily transferred its stock exchange listing from the New York Stock Exchange (NYSE). The ticker symbol remains "XEL."

Xcel Energy Board of Directors

Richard K. Davis ^{2,3}

Executive Chairman
U.S. Bancorp

Ben Fowke

Chairman, President and CEO
Xcel Energy Inc.

Richard T. O'Brien ^{1,4}

Independent Consultant

David K. Owens ^{3,4}

Retired Executive
Edison Electric Institute

Christopher J. Policinski ²

Lead Independent Director
President and CEO
Land O' Lakes, Inc.

James Prokopanko ^{2,4}

Retired President and CEO
The Mosaic Company

A. Patricia Sampson ^{1,3}

CEO, President and Owner
The Sampson Group, Inc.

James J. Sheppard ^{2,4}

Independent Consultant

David A. Westerlund ^{1,2}

Retired Executive Vice President,
Administration and Corporate Secretary
Ball Corporation

Kim Williams ^{1,3}

Retired Partner
Wellington Management Company LLP

Timothy V. Wolf ^{3,4}

President
Wolf Interests, Inc.

Daniel Yohannes ^{1,3}

Former United States Ambassador
to the Organization for Economic
Cooperation and Development

Board Committees:

1. Audit
2. Governance, Compensation and Nominating
3. Finance
4. Operations, Nuclear, Environmental and Safety



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
150 East 42nd Street, 40th Floor,
New York, NY 10017



THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)



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)

Northern States Power Company (Minnesota)

Year/Period of Report

End of 2017/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.)

<u>Reference Schedules</u>	<u>Pages</u>
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 filed..."

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).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)		02 Year/Period of Report End of <u>2017/Q4</u>
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /		
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 414 Nicollet Mall, Minneapolis, MN 55401		
05 Name of Contact Person Jeffrey S. Savage		06 Title of Contact Person Sr. Vice Pres., Controller
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, <i>Including Area Code</i> (612) 330-5658	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report <i>(Mo, Da, Yr)</i> 04/06/2018

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 Jeffrey S. Savage	03 Signature Jeffrey S. Savage	04 Date Signed <i>(Mo, Da, Yr)</i> 04/06/2018
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.

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	N/A
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent

Northern States Power Company (Minnesota)

This Report Is:

(1) An Original(2) A Resubmission

Date of Report

(Mo, Da, Yr)

04/06/2018

Year/Period of Report

End of 2017/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

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	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input checked="" type="checkbox"/> Two copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	--	--

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, Controller
414 Nicollet Mall
Minneapolis, MN 55401

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.

Northern States Power Co. (a Minnesota coporation) was incorporated in the state of Minnesota on March 9, 2000.

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.

During the year 2017, the respondent furnished electric utility and natural gas utility service in the states of Minnesota and North Dakota and electric utility and intrastate natural gas transportation service in the state of South Dakota.

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) No

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	---	--

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

Northern States Power Co. (a Minnesota corporation) is a first tier subsidiary of Xcel Energy Inc.

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)
1	NSP Nuclear Corp	Holds NSP's interest in	100	
2		Nuclear Mgmt Co. LLC		
3	Nuclear Mgmt Co. LLC	Manages nuclear power plants	100	
4	Private Fuel Storage, LLC	Nuclear waste storage	32.8	
5	United Power and Land Co.	Real estate holdings	100	
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

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	Chairman of the Board, Chief Executive Officer	Ben Fowke	523,564
2	Senior Vice President, Chief Nuclear Officer	Timothy J. O'Connor	500,000
3	President	Christopher B. Clark	340,000
4	Executive Vice President, Chief Financial Officer	Robert C. Frenzel	247,478
5	Executive Vice President	Marvin E. McDaniel, Jr.	232,149
6	Executive Vice President	Kent T. Larson	213,172
7	Executive Vice President, General Counsel	Scott M. Wilensky	194,575
8	Senior Vice President, Corporate Secretary	Judy M. Poferl	145,344
9	Senior Vice President, Controller	Jeffrey S. Savage	121,120
10	Vice President, Treasurer	Brian J. Van Abel	116,390
11			
12			
13	Salaries represent NSP-Minnesota's allocation of		
14	officers' salaries greater than \$50,000 for the period		
15	of time that was served as an officer for		
16	NSP-Minnesota.		
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			
42			
43			
44			

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)
1	Ben Fowke, Chairman of the Board, Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401
2	Robert C. Frenzel, Executive Vice President, CFO	414 Nicollet Mall, Minneapolis, MN 55401
3	Christopher B. Clark, President	414 Nicollet Mall, Minneapolis, MN 55401
4	Marvin E. McDaniel, Jr., Executive Vice President	414 Nicollet Mall, Minneapolis, MN 55401
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		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of 2017/Q4
---	---	--	---

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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	FERC Electric Tariff, Third Revised Volume No. 1	ER07-1415-000 - Order Granting Incentives,
2	(Midwest Independent Transmission System	and Accepting Proposed Rate Formula
3	Operator, Inc. Open Access Transmission and	Modifications, Subject to Conditions, Issued
4	Energy Markets Tariff, Attachment O-NSP)	December 21, 2007, Accession No. 20071221-3012
5		
6	FERC Electric Tariff, Fourth Revised Volume No. 1	ER10-541-000 - Approval of Tariff Revisions to
7	(Midwest Independent Transmission System	Attachment O-NSP, Issued February 26, 2010,
8	Operator, Inc. Open Access Transmission and	Accession No. 20100226-3041.
9	Energy Markets Tariff, Attachment O-NSP)	
10		
11	FERC Electric Tariff updated effective 01-01-2012	ER12-297-000 - Approval of Tariff Revisions to
12	(Midwest Independent Transmission System	Attachment O-NSP, Issued December 21, 2011,
13	Operator, Inc. Open Access Transmission and	Accession No. 20111221-3033.
14	Energy Markets Tariff, Attachment O-NSP)	
15		
16	FERC Electric Tariff updated effective 01-01-2013	ER13-674-000/001/002 Approval of Tariff Revisions
17	(Midwest Independent Transmission System	to Attachment O-NSP, Issued March 20, 2013,
18	Operator, Inc. Open Access Transmission and	Accession No. 20130320-3014
19	Energy Markets Tariff, Attachment O-NSP)	
20		
21	FERC Electric Tariff updated effective 11-19-2013	ER14-421-000/001 Approval of Tariff Revisions
22	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued March 11, 2014,
23	Operator, Inc. Open Access Transmission and	Accession No. 20140311-3041
24	Energy Markets Tariff, Attachment O-NSP,	
25	Attachment GG-NSP; & Attachment MM)	
26		
27	FERC Electric Tariff updated effective 01-06-2015	ER15-358-000 Approval of Tariff Revisions
28	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued January 6, 2015,
29	Operator, Inc. Open Access Transmission and	Accession No. 20150105-3035
30	Energy Markets Tariff, Attachment O-NSP)	
31		
32	FERC Electric Tariff updated effective 01-01-2016	ER16-197-000 Approval of Tariff Revisions
33	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 30, 2015,
34	Operator, Inc. Open Access Transmission and	Accession No. 20151230-3075
35	Energy Markets Tariff, Attachment O-NSP)	
36		
37	FERC Electric Tariff updated effective 01-01-2017	ER17-305-000 Approval of Tariff Revisions
38	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 30, 2016,
39	Operator, Inc. Open Access Transmission and	Accession No. 20161230-3022
40	Energy Markets Tariff, Attachment O-NSP)	
41		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of 2017/Q4
---	---	--	---

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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	FERC Electric Tariff updated effective 12-01-2017	ER18-12-000 Approval of Tariff Revisions
2	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued November 29, 2017,
3	Operator, Inc. Open Access Transmission and	Accession No. 20171129-3095
4	Energy Markets Tariff, Attachment O-NSP)	
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		
41		

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)?

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	20170308-5088	03/08/2017	ER17-1120-000	See footnote	FERC Electric Tariff updated effective
2					01-01-2017 (Midcontinent Independent
3					System Operator, Inc. Open
4					Access Transmission and Energy
5					Markets Tariff, Attachment O-NSP)
6					
7	20180313-5128	03/13/2018	ER18-1004-000	See footnote	FERC Electric Tariff updated effective
8					01-01-2018 (Midcontinent Independent
9					System Operator, Inc. Open Access
10					Transmission and Energy Markets Tariff,
11					Attachment O-NSP)
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					
41					
42					
43					
44					
45					
46					

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 1061 Line No.: 1 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER17-1120-0000

Schedule Page: 1061 Line No.: 7 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER18-1004-0000

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
1	111	Comp Balance Sheet Assets and Other Dfrd Debits		(c) 57
2	204	Electric Plant in Service (Acct 101, 102, 103,106)		(g) 5, 46, 58, 75, 99
3	214	Electric Plant Held for Future Use (Acct 105)		(d) 46
4	216.1	Construction Work in Progress- Electric (Acct 107)		(b) 41
5	219	Accum Prov for Depr of Elect Util Plant (Acct 108)		(c) 20-26, 28
6	227	Materials and Supplies		(a) 18
7	234	Accumulated Deferred Income Taxes (Acct 190)		(c) 8
8	267	Accum. Deferred Investment Tax Credits (Acct 225)		(h) 8
9	269	Other Deferred Credits (Acct 253)		(d), (e) 35
10	269	Other Deferred Credits (Acct 253)		(a) 44
11	272	Accumulated Deferred Income Taxes (Acct 281)		(k) 8
12	274	Accumulated Deferred Income Taxes (Acct 282)		(k) 2
13	276	Accumulated Deferred Income Taxes (Acct 283)		(b) 3
14	300	Electric Operating Revenues (Acct 400)		(b) 19
15	310.1	Sales for Resale (Acct 447)		(a) 13
16	321	Electric Operation and Maintenance Expenses		(b) 112
17	328	Transmission of Electricity for Others		(a) 19
18	356.2	Common Utility Plant and Expenses		n/a n/a
19				
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				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	------------------------------	--

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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. Franchise – The following franchises were acquired from the representative local government body without payment of consideration:

City	State	Utility	Expiration
Morgan	Minn.	Electric	Jan. 3, 2037
East Gull Lake	Minn.	Gas	Feb. 6, 2037
Briarwood	N.D.	Gas	April 17, 2037
Pipestone	Minn.	Electric	June 4, 2037
Prairie Rose	N.D.	Gas	June 5, 2037
Nisswa	Minn.	Gas	June 20, 2037
LaCrescent	Minn.	Electric	July 10, 2037
Eagan	Minn.	Gas	July 30, 2037
Thompson	N.D.	Gas	Aug. 6, 2037
Nerstrand	Minn.	Electric	Sept. 11, 2037

2. Acquisitions

None

3. Purchase or sale of an operating unit or 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 activities.

7. Changes in articles of incorporation and amendments to charter

None

8. Wage scale changes

Union Employees - Contract base increases ranging from 2.00 - 2.60 percent effective Jan. 1, 2017.

Union Employees - Contract base increase of 2.50 percent effective Sept. 1, 2017 (Prairie Island Engineering Section).

Non-Union Employees - Merit base increase of 3.00 percent effective March 16, 2017.

9. Legal proceedings

See Note 9 of the Financial Statements on page 123 for disclosures regarding material legal proceedings.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/06/2018	2017/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

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

Xcel Energy (including NSP-Minnesota) has perviously announced that Marvin E. McDaniel, Jr. will retire in 2018.

14. Cash management programs

Not applicable as proprietary capital ratio is greater than 30 percent.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of 2017/Q4
---	---	--	---

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	19,299,054,693	19,263,104,804
3	Construction Work in Progress (107)	200-201	529,931,771	509,028,925
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		19,828,986,464	19,772,133,729
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,766,026,424	7,413,415,120
6	Net Utility Plant (Enter Total of line 4 less 5)		12,062,960,040	12,358,718,609
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	182,412,823	205,525,449
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		535,339,673	526,657,578
10	Spent Nuclear Fuel (120.4)		1,979,659,426	1,839,587,125
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,294,997,690	2,180,635,866
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		402,414,232	391,134,286
14	Net Utility Plant (Enter Total of lines 6 and 13)		12,465,374,272	12,749,852,895
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		13,785,198	13,264,783
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,240,557	10,689,874
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,446,176	2,573,107
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)		49,062,277	44,297,238
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,143,532,093	1,861,011,461
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		28,102,000	24,678,410
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,224,687,187	1,935,135,125
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		12,406,411	15,842,241
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		122,380	124,640
38	Temporary Cash Investments (136)		31,155,929	31,490,417
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		327,940,750	310,862,746
41	Other Accounts Receivable (143)		47,916,248	77,639,403
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		21,278,289	19,967,629
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		48,494,400	51,390,452
45	Fuel Stock (151)	227	97,129,106	100,686,129
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	208,454,636	213,287,451
49	Merchandise (155)	227	752,710	942,563
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	28,206	4,067

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)		27,153,915	24,872,348
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		4,193,243	5,399,564
57	Prepayments (165)		108,201,247	54,995,859
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		28,492	0
60	Rents Receivable (172)		714,254	708,269
61	Accrued Utility Revenues (173)		277,715,906	259,590,461
62	Miscellaneous Current and Accrued Assets (174)		0	89,560
63	Derivative Instrument Assets (175)		53,224,887	46,706,476
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		28,102,000	24,678,410
65	Derivative Instrument Assets - Hedges (176)		107,246	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,196,359,677	1,149,986,607
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		45,246,916	39,906,558
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	61,711,558	65,060,122
72	Other Regulatory Assets (182.3)	232	3,562,449,742	3,297,860,533
73	Prelim. Survey and Investigation Charges (Electric) (183)		425,348	5,524,543
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	46,922,173	62,619,320
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)		19,797,204	13,434,928
82	Accumulated Deferred Income Taxes (190)	234	783,099,188	1,037,767,852
83	Unrecovered Purchased Gas Costs (191)		22,322,051	25,641,559
84	Total Deferred Debits (lines 69 through 83)		4,541,974,180	4,547,815,415
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		20,428,395,316	20,382,790,042

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 57 Column: c

Prepayments (Account No. 165). The Form 1 reports prepayments at the total Company level, 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 the year prepayments balance in the formula. In addition, since prepayments are reported in the Form 1 at the total Company level, they are allocated to the electric utility based on the ratio of electric net plant to the sum of electric and gas net plant as reported in the Form 1, page 200. The formula allocates the electric prepayments to the transmission function using a gross plant allocator.

NSP-Minnesota's Prepayments (Account No. 165) balance at Dec. 31, 2017, includes \$79,089,342 for income taxes. This balance was largely driven by an overpayment for 2017 income taxes, and a reserve for the Internal Revenue Service audits, a portion of which is currently in Appeals. NSP-Minnesota expects the overpayment for 2017 will be settled in 2018 after the Xcel Energy extensions and tax returns are filed.

Schedule Page: 110 Line No.: 57 Column: d

NSP-Minnesota's Prepayments (Account No. 165) balance at Dec. 31, 2016, includes \$25,549,302 for income taxes. This balance was largely driven by an overpayment for 2016 income taxes, and a reserve for the Internal Revenue Service audits, a portion of which was in Appeals. NSP-Minnesota's overpayment for 2016 was settled in 2017 after the Xcel Energy extensions and tax returns were filed.

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (mo, da, yr) 04/06/2018	Year/Period of Report end of 2017/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	10,000	10,000
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)		479,282,529	479,282,529
7	Other Paid-In Capital (208-211)	253	3,100,951,102	2,955,813,212
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	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,922,799,303	1,944,055,826
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,936,745	-2,809,856
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)	-24,536,486	-20,782,709
16	Total Proprietary Capital (lines 2 through 15)		5,475,569,703	5,355,569,002
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	5,000,000,000	4,900,000,000
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	35,044	22,518
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		21,770,166	16,951,568
24	Total Long-Term Debt (lines 18 through 23)		4,978,264,878	4,883,070,950
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		776,242	922,463
29	Accumulated Provision for Pensions and Benefits (228.3)		291,586,000	332,000,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		15,076,073	43,538,172
32	Long-Term Portion of Derivative Instrument Liabilities		102,741,828	116,804,317
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,083,873,501	2,452,566,787
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,494,053,644	2,945,831,739
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		20,000,000	85,000,000
38	Accounts Payable (232)		400,979,008	411,095,526
39	Notes Payable to Associated Companies (233)		86,450,000	1,450,000
40	Accounts Payable to Associated Companies (234)		82,278,729	59,633,299
41	Customer Deposits (235)		95,368,970	110,244,496
42	Taxes Accrued (236)	262-263	225,009,647	219,084,491
43	Interest Accrued (237)		65,404,903	69,594,249
44	Dividends Declared (238)		98,687,400	89,428,150
45	Matured Long-Term Debt (239)		0	0

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 112 Line No.: 7 Column: d

In 2016 an adjustment was recorded to move the life to date contributions of capital from FERC Account No. 207, Premium on Capital Stock, to FERC Account No. 211, Miscellaneous Paid-In Capital.

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 column in 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	4,951,746,389	4,845,209,645		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,939,483,149	2,817,193,281		
5	Maintenance Expenses (402)	320-323	245,544,721	276,281,879		
6	Depreciation Expense (403)	336-337	600,009,273	562,969,977		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	18,214,959	30,382,102		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	54,804,320	50,715,975		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		3,781,885	3,544,366		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		60,170,809	46,895,788		
13	(Less) Regulatory Credits (407.4)		211,280,280	205,262,154		
14	Taxes Other Than Income Taxes (408.1)	262-263	254,892,511	246,436,047		
15	Income Taxes - Federal (409.1)	262-263	12,922,632	20,351,273		
16	- Other (409.1)	262-263	11,128,872	11,230,260		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	642,433,406	751,486,500		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	474,936,373	553,889,597		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,647,628	-1,662,650		
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)		6,365,726	3,939,977		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		121,988,404	115,649,669		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,271,144,934	4,168,382,739		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		680,601,455	676,826,906		

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		Line No.
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)	
4,430,077,743	4,376,218,559	521,668,646	468,991,086			2
						3
2,533,439,819	2,460,909,086	406,043,330	356,284,195			4
237,023,256	268,989,617	8,521,465	7,292,262			5
555,886,845	521,186,468	44,122,428	41,783,509			6
17,904,087	30,122,828	310,872	259,274			7
49,785,532	46,423,974	5,018,788	4,292,001			8
						9
3,781,885	3,544,366					10
						11
60,170,809	46,895,788					12
193,664,890	199,269,502	17,615,390	5,992,652			13
232,574,892	225,207,847	22,317,619	21,228,200			14
12,190,826	24,558,674	731,806	-4,207,401			15
10,799,183	11,489,371	329,689	-259,111			16
597,898,132	693,256,554	44,535,274	58,229,946			17
439,607,719	512,418,192	35,328,654	41,471,405			18
-1,383,956	-1,390,399	-263,672	-272,251			19
						20
						21
6,365,726	3,939,977					22
						23
120,514,242	114,541,540	1,474,162	1,108,129			24
3,790,947,217	3,730,108,043	480,197,717	438,274,696			25
639,130,526	646,110,516	41,470,929	30,716,390			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		680,601,455	676,826,906		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility 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)		28,334,432	28,263,966		
34	(Less) Expenses of Nonutility Operations (417.1)		21,566,837	23,234,805		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-126,890	-79,953		
37	Interest and Dividend Income (419)		4,307,708	94,766		
38	Allowance for Other Funds Used During Construction (419.1)		29,513,860	27,731,929		
39	Miscellaneous Nonoperating Income (421)		3,421,667	-1,059,672		
40	Gain on Disposition of Property (421.1)		1,161,437			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		45,045,377	31,716,231		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		38,999			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,864,072	6,651,473		
46	Life Insurance (426.2)		-2,933,511	-3,206,963		
47	Penalties (426.3)		98,501	192,393		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,762,332	2,312,930		
49	Other Deductions (426.5)		2,627,599	2,105,925		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,457,992	8,055,758		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	198,503	177,835		
53	Income Taxes-Federal (409.2)	262-263	4,527,490	109,423		
54	Income Taxes-Other (409.2)	262-263	4,662,787	-1,689,321		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	20,103,254	22,452,084		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	19,491,836	23,813,032		
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)		10,000,198	-2,763,011		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		29,587,187	26,423,484		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		220,363,148	215,414,227		
63	Amort. of Debt Disc. and Expense (428)		4,326,415	4,251,253		
64	Amortization of Loss on Reaquired Debt (428.1)		1,999,600	1,933,092		
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)		1,124,353	315,226		
68	Other Interest Expense (431)		7,308,402	5,164,288		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,054,582	12,571,378		
70	Net Interest Charges (Total of lines 62 thru 69)		220,067,336	214,506,708		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		490,121,306	488,743,682		
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)		490,121,306	488,743,682		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 114 Line No.: 12 Column: c

	Electric	Gas
Minnesota Renewable Development Fund	\$ 31,186,735	
Minnesota Renewable Energy Standard	9,680,536	
North Dakota Renewable Energy Rider	528,818	
North Dakota Transmission Cost Recovery	786,206	
Private Fuel Storage	57,795	
Sherco Unit 3 Depreciation Deferral	439,464	
South Dakota Infrastructure	529,020	
South Dakota Production Tax Credit	6,214,326	
South Dakota Transmission Cost Recovery	1,341,476	
Theoretical Depreciation Reserve Surplus	9,406,433	
	\$ 60,170,809	

Schedule Page: 114 Line No.: 12 Column: d

	Electric	Gas
Minnesota Renewable Development Fund	\$ 28,210,993	
Minnesota Revenue Decoupling Mechanism	1,781,212	
Minnesota Transmission Cost Recovery	11,013,382	
North Dakota Renewable Energy Rider	578,236	
Private Fuel Storage	109,819	
Sherco Unit 3 Depreciation Deferral	439,537	
South Dakota Production Tax Credit	4,548,992	
Transco Amortization	213,617	
	\$ 46,895,788	

Schedule Page: 114 Line No.: 13 Column: c

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 138,418,327	\$ 1,785,035
LED Streetlighting	686,612	
Minnesota Gas Utility Infrastructure		15,495,696
Minnesota Revenue Decoupling Mechanism	28,008,662	
Minnesota Sales True Up	22,667,433	
Minnesota State Energy Policy		334,659
Minnesota Transmission Cost Recovery	3,830,452	
Transco Amortization	53,404	
	\$ 193,664,890	\$ 17,615,390

Schedule Page: 114 Line No.: 13 Column: d

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 144,664,127	\$ 1,367,645
Minnesota Gas Utility Infrastructure		3,794,505
Minnesota Renewable Energy Standard	3,236,115	
Minnesota State Energy Policy		830,502
North Dakota Transmission Cost Recovery	140,817	
South Dakota Transmission Cost Recovery	645,586	
Theoretical Depreciation Reserve Surplus	50,493,485	
South Dakota Infrastructure	89,372	
	\$ 199,269,502	\$ 5,992,652

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.

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		1,943,978,203	1,866,978,569
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Reclassification of Tax Effects from Account 219	219	4,348,780	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		4,348,780	
10				
11	Rounding		1	(1)
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		1	(1)
16	Balance Transferred from Income (Account 433 less Account 418.1)		490,248,196	488,823,635
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			-515,853,500	(411,824,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-515,853,500	(411,824,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,922,721,680	1,943,978,203
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		77,623	77,623
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		77,623	77,623
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,922,799,303	1,944,055,826
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,809,856	(2,729,903)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-126,890	(79,953)
51	(Less) Dividends Received (Debit)			
52	Rounding		1	
53	Balance-End of Year (Total lines 49 thru 52)		-2,936,745	(2,809,856)

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 4 Column: c

On March 19, 2018, the Edison Electric Institute requested that FERC grant blanket approval for public utilities and centralized service companies to use Account 439 to record reclassifications of "accumulated other comprehensive income" to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act (Docket No. AC18-59-000). Commission action is pending.

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)	490,121,306	488,743,682
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	677,293,963	595,142,891
5	Amortization of Nuclear Fuel	114,361,824	116,981,547
6	Amortization of Premium, Discount and Debt Expense	6,326,015	6,184,345
7	Net Gain on Disposition of Property	-1,122,438	
8	Deferred Income Taxes (Net)	168,108,451	196,235,955
9	Investment Tax Credit Adjustment (Net)	-1,647,628	-1,662,650
10	Net (Increase) Decrease in Receivables	17,807,675	-54,699,563
11	Net (Increase) Decrease in Inventory	7,665,691	-1,117,628
12	Net (Increase) Decrease in Allowances Inventory	-24,139	2,561
13	Net Increase (Decrease) in Payables and Accrued Expenses	53,211,626	54,733,176
14	Net (Increase) Decrease in Other Regulatory Assets	-141,163,039	-10,248,431
15	Net Increase (Decrease) in Other Regulatory Liabilities	113,170,120	72,092,209
16	(Less) Allowance for Other Funds Used During Construction	29,513,860	27,731,929
17	(Less) Undistributed Earnings from Subsidiary Companies	-126,889	-79,953
18	Other: (Increase) Decrease in Accrued Utility Revenues	-18,125,445	-32,488,910
19	Other: Net Realized and Unrealized Hedging and Derivative Transactions	-2,783,828	3,729,421
20	Other: Changes in Other Current Assets and Liabilities	-70,718,178	7,586,434
21	Other: Changes in Noncurrent Liabilities and Deferred Amounts	-110,353,183	-108,478,866
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,272,741,822	1,305,084,197
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-738,665,574	-983,799,643
27	Gross Additions to Nuclear Fuel	-125,641,770	-124,638,474
28	Gross Additions to Common Utility Plant	-152,375,366	-96,098,451
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-29,513,860	-27,731,929
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-987,168,850	-1,176,804,639
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		-100,000
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Investments in Utility Money Pool Arrangement	-122,000,000	-747,500,000
44	Purchase of Investment Securities (a)	-1,248,712	-7,060,431
45	Proceeds from Sales of Investment Securities (a)		

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	Repayments from Utility Money Pool Arrangement	122,000,000	747,500,000
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: Miscellaneous Other Investing Activities	-3,516,327	-1,043,265
54	Other: Purchase of Investments in External Decommissioning Fund	-1,689,281,473	-499,237,578
55	Other: Proceeds from Sale of Investments in External Decommissioning	1,668,909,725	478,865,830
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,012,305,637	-1,205,380,083
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	585,247,832	342,502,577
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions by Parent	145,003,018	96,672,311
65	Other: Borrowings Under Utility Money Pool Arrangement	838,000,000	424,000,000
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,568,250,850	863,174,888
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-507,865,363	-10,882
74	Preferred Stock		
75	Common Stock		
76	Other: Repayments under Utility Money Pool Arrangement	-753,000,000	-424,000,000
77			
78	Net Decrease in Short-Term Debt (c)	-65,000,000	-138,000,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-506,594,250	-395,893,400
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-264,208,763	-94,729,394
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-3,772,578	4,974,720
87			
88	Cash and Cash Equivalents at Beginning of Period	47,457,298	42,482,578
89			
90	Cash and Cash Equivalents at End of period	43,684,720	47,457,298

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 21 Column: b

<u>Changes in Noncurrent Liabilities and Deferred Amounts</u>	
Change in pension and employee benefit obligation	\$ (58,417,849)
Change in deferred debits	26,411,218
Change in deferred credits	(49,738,233)
Change in noncurrent liabilities	(28,608,319)
	\$ <u>(110,353,183)</u>

Schedule Page: 120 Line No.: 21 Column: c

<u>Changes in Noncurrent Liabilities and Deferred Amounts</u>	
Change in pension and employee benefit obligation	\$ (41,394,473)
Change in deferred debits	(16,699,226)
Change in deferred credits	(32,311,933)
Change in noncurrent liabilities	(18,073,234)
	\$ <u>(108,478,866)</u>

Schedule Page: 120 Line No.: 90 Column: b

Cash and Working Funds (130)	\$ 0
Cash (131)	12,406,411
Working Fund (135)	122,380
Temporary Cash Investments (136)	31,155,929
Cash and Cash Equivalents at End of Period	\$ <u>43,684,720</u>

Schedule Page: 120 Line No.: 90 Column: c

Cash and Working Funds (130)	\$ 0
Cash (131)	15,842,241
Working Fund (135)	124,640
Temporary Cash Investments (136)	31,490,417
Cash and Cash Equivalents at End of Period	\$ <u>47,457,298</u>

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	------------------------------	--

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 Commission 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

1. Summary of Significant Accounting Policies

Business and System of Accounts — Northern States Power Co., a Minnesota Corporation (NSP-Minnesota), is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota is subject to regulation by the Federal Energy Regulatory Commission (FERC) and state utility commissions.

The electric production and transmission system of NSP-Minnesota and Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin), (collectively, NSP System) is operated on an integrated basis and managed by NSP-Minnesota and NSP-Wisconsin. The electric production and transmission costs of the NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

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.
- 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 the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation within the utility plant accounts in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- 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 the 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.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for the FERC presentation and reported as operating expenses for the 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 the GAAP presentation as a below-the-line deduction from operating income.
- Certain utility plant cost disallowances are presented as an extraordinary deduction in the FERC presentation in contrast to the GAAP presentation in which they are included in operating expenses.
- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- Adjustments to theoretical excess depreciation reserves are recorded as a regulatory asset and an increase to regulatory credits for FERC presentation, in contrast to a reduction to both accumulated depreciation and depreciation expense for GAAP presentation.
- 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.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by the FERC presentation of:

(Thousands of Dollars)

Balance Sheet:

Net utility plant	\$	568,238
Current assets		280,902
Current liabilities		147,644
Other long-term assets		(3,351,644)
Long-term debt and other long-term liabilities		(2,650,150)

Statement of Income:

Operating revenues	\$	150,281
Operating expenses		(37,088)
Other income and deductions		5,590
Interest Charges		(6,721)

Statement of Cash Flows:

Cash provided by operating activities	\$	(43)
Cash used in investing activities		1
Cash provided by financing activities		1

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Regulatory Accounting — NSP-Minnesota accounts for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

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

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

If restructuring or other changes in the regulatory environment occur, NSP-Minnesota 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 NSP-Minnesota's financial condition, results of operations and cash flows. See Note 13 for further discussion of regulatory assets and liabilities.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is recognized. NSP-Minnesota presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in Midcontinent Independent System Operator, Inc. (MISO). NSP-Minnesota recognizes sales to both native load and other end use customers on a net basis in cost of sales. Revenues and charges transacted through Regional Transmission Organizations (RTOs) are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon the total volumes. The real time and day-ahead market are each evaluated separately. If NSP-Minnesota is a net seller the transaction is recorded on a gross basis in electric revenues and cost of sales. If NSP-Minnesota is a net buyer the transaction is recorded on a net basis in cost of sales.

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

Certain rate rider mechanisms qualify as alternative revenue programs under generally accepted accounting principles. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, revenue is recognized equal to the revenue requirement, including return on rate base items, for the qualified mechanisms. The mechanisms are revised periodically for differences between the total amount collected under the riders and the revenue recognized, which may increase or decrease the level of revenue collected from customers.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Conservation Programs — NSP-Minnesota has implemented programs in its retail jurisdictions to assist customers in reducing peak demand and conserving energy on the electric and natural gas system. These programs include a wide variety of programs including, but not limited to, commercial process efficiency and lighting upgrades, as well as incentives for participation in air-conditioning interruption.

The costs incurred for conservation improvement programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Recorded revenues for incentive programs designed for recovery of 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.

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

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate.

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

NSP-Minnesota records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.6 and 3.2 percent for the years ended Dec. 31, 2017 and 2016, respectively.

Leases — NSP-Minnesota evaluates a variety of contracts for lease classification at inception, including purchase power agreements (PPAs) and rental arrangements for office space, vehicles, and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 9 for further discussion of leases.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota’s rate base for establishing utility service rates.

Generally AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases, including certain wind and transmission projects, the Minnesota Public Utilities Commission (MPUC) or the FERC have approved a more current recovery of the cost of capital associated with large capital projects, through various riders, resulting in a lower recognition of AFUDC.

AROs — NSP-Minnesota 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 recording of the obligation for regulated operations has no income statement impact due to the deferral of the amounts through the establishment of a regulatory asset and recovery in rates. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs. See Note 9 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota’s ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota’s most recent triennial nuclear decommissioning studies were filed with the MPUC in December 2017. These studies reflect NSP-Minnesota’s plans for dismantlement of the Monticello and Prairie Island (PI) facilities. These studies assume that NSP-Minnesota will store spent fuel on site pending removal to a United States government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility’s expected service life based on the triennial decommissioning studies filed with the MPUC and other state commissions. 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. See Note 10 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota’s nuclear facilities are included in nuclear decommissioning fund and deferred debits on the balance sheets. See Note 7 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota’s nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC) and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling operating costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

The effects of NSP-Minnesota's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset. 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, the reversal of some temporary differences are accounted for as current income tax expense. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 11.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available evidence is considered, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations.

NSP-Minnesota 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. NSP-Minnesota 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.

Interest and penalties are recorded separately to their respective line items in the income statement.

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

See Note 5 for further discussion of income taxes.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Types of and Accounting for Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations including transmission in organized markets and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and operating costs; and interest rate hedging transactions are recorded as a component of interest expense. NSP-Minnesota is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. For further information on derivatives entered to mitigate commodity price risk on behalf of electric and natural gas customers, see Note 7.

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

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

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

See Note 7 for further discussion of NSP-Minnesota's risk management and derivative activities.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of NSP-Minnesota's commodity trading margins are apportioned to Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS). Commodity trading activities are not associated with energy produced from NSP-Minnesota'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. For further information, see Note 7.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets 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 as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the pension and postretirement plan assets and the 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 6 and 7 for further discussion.

Cash and Cash Equivalents — NSP-Minnesota considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

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

Inventory — All inventory is recorded at average cost.

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

When RECs are purchased or acquired in the course of generation they are recorded as inventory at cost in Account 158.1. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense.

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

Emission Allowances — Emission allowances, including the annual sulfur dioxide (SO₂) and nitrogen oxide (NO_x) emission allowance entitlement received from the United States Environmental Protection Agency (EPA), are recorded at cost plus associated broker commission fees. NSP-Minnesota follows the inventory accounting model for all emission allowances. Sales of emission allowances are included in electric utility operating revenues and the operating activities section of the statements of cash flows.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Estimated remediation costs, excluding inflationary increases, are recorded based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties (PRPs) exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost.

Any future costs of restoring sites where operation may be extended are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. See Note 9 for further discussion of environmental costs.

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

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

See Note 6 for further discussion of benefit plans and other postretirement benefits.

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

The obligation recognized is reduced over the term of the guarantee as NSP-Minnesota is released from risk under the guarantee. See Note 9 for specific details of issued guarantees.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2017 up to Feb. 26, 2018, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 6, 2018. These statements contain all necessary adjustments and disclosures resulting from these evaluations.

2. Investments Accounted for by the Equity Method

In accordance with FERC regulations, NSP-Minnesota's investment in and income from all of its wholly owned subsidiaries are presented using the equity method of accounting. Subsidiaries accounted for under the equity method include:

<u>Name</u>	<u>Geographic Area</u>	<u>Economic Interest</u>
United Power & Land	United States	100%
NSP-Nuclear Corp.	United States	100%
Private Fuel Storage, LLC*	United States	32.8%

*The investment in Private Fuel Storage, LLC has been written down to zero.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Summarized Financial Information of Unconsolidated Investees:

Summarized financial information for all equity-method subsidiaries and projects, including interests owned by NSP-Minnesota was as follows:

(Thousands of Dollars)	2017	2016
Current assets	\$ 1,552	\$ 1,607
Other assets	1,055	1,192
Total assets	<u>\$ 2,607</u>	<u>\$ 2,799</u>
Current liabilities	\$ 146	\$ 213
Other liabilities	15	13
Equity	2,446	2,573
Total liabilities and equity	<u>\$ 2,607</u>	<u>\$ 2,799</u>

(Thousands of Dollars)	2017	2016
Operating revenues	\$ 20	\$ 45
Operating loss	(161)	(145)
Net Loss	(127)	(80)

3. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. Money pool borrowings for NSP-Minnesota were as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2017	Twelve Months Ended Dec. 31, 2016
Borrowing limit	\$ 250	\$ 250
Amount outstanding at period end	85	—
Average amount outstanding	25	16
Maximum amount outstanding	142	225
Weighted average interest rate, computed on a daily basis	1.14%	0.69%
Weighted average interest rate at period end	1.18%	N/A

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Commercial Paper — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2017	Twelve Months Ended Dec. 31, 2016
Borrowing limit	\$ 500	\$ 500
Amount outstanding at period end	20	85
Average amount outstanding	62	73
Maximum amount outstanding	237	353
Weighted average interest rate, computed on a daily basis	1.10%	0.65%
Weighted average interest rate at end of period	1.93	0.94

Letters of Credit — NSP-Minnesota uses letters of credit, generally with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2017 and 2016, there were \$24 million and \$11 million of letters of credit outstanding, respectively, 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, NSP-Minnesota 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 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.

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

Other features of NSP-Minnesota's credit facility include:

- NSP-Minnesota may increase its credit facility by up to \$100 million.
- The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65 percent. NSP-Minnesota was in compliance as its debt-to-total capitalization ratio was 48 percent at both Dec. 31, 2017 and 2016. If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.
- The credit facility has a cross-default provision that provides NSP-Minnesota will be in default on its borrowings under the facility if NSP-Minnesota or any of its subsidiaries whose total assets exceed 15 percent of NSP-Minnesota's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding \$75 million.
- NSP-Minnesota was in compliance with all financial covenants on its debt agreements as of Dec. 31, 2017 and 2016.

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

Credit Facility (a)	Drawn (b)	Available
\$ 500	\$ 44	\$ 456

(a) This credit facility matures in June 2021.

(b) Includes outstanding commercial paper and letters of credit.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota 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 associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

In 2017, NSP-Minnesota issued \$600 million of 3.6 percent first mortgage bonds due Sept. 15, 2047. In 2016, NSP-Minnesota issued \$350 million of 3.6 percent first mortgage bonds due May 15, 2046.

During the next five years, NSP-Minnesota has long-term debt maturities of \$300 million due in both 2020 and 2022, respectively.

Deferred Financing Costs — Deferred financing costs of approximately \$45 million and \$40 million, net of amortization, are presented as deferred debits at Dec. 31, 2017 and 2016, respectively. NSP-Minnesota is amortizing these financing costs over the remaining maturity periods of the related debt.

Dividend and Other Capital-Restrictions — NSP-Minnesota’s dividends are subject to the FERC’s jurisdiction, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

NSP-Minnesota’s first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with this restriction, NSP-Minnesota could have paid more than \$1.9 billion and \$1.7 billion in additional cash dividends on common stock as of Dec. 31, 2017 and 2016, respectively.

The most restrictive dividend limitation for NSP-Minnesota is imposed by its state regulatory commissions. NSP-Minnesota’s state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 47.2 percent and 57.6 percent. NSP-Minnesota’s equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2017 and \$1.1 billion in retained earnings was not restricted. Total capitalization for NSP-Minnesota was \$10.4 billion at Dec. 31, 2017, which did not exceed the limits imposed by the commissions of \$11.2 billion.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

4. Joint Ownership of Generation and Transmission Facilities

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

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation ^(a)	CWIP	Ownership %
Electric Generation:				
Sherco Unit 3	\$ 612,219	\$ 410,247	\$ 486	59%
Sherco Common Facilities Units 1, 2 and 3	145,102	98,867	967	80
Sherco Substation	4,790	3,228	—	59
Electric Transmission:				
Grand Meadow Line and Substation	10,647	2,087	—	50
CapX2020 Transmission	1,038,790	138,133	2,081	51
Total	\$ 1,811,548	\$ 652,562	\$ 3,534	

(a) Asset retirement obligation is not included.

NSP-Minnesota has approximately 517 megawatts (MW) of jointly owned generating capacity. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

5. Income Taxes

Federal Tax Reform — In December 2017, the 2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act (TCJA) was signed into law. While the legislation will require interpretations and regulations to be issued by the Internal Revenue Service (IRS), the key provisions impacting Xcel Energy (which includes NSP-Minnesota) generally beginning in 2018, include:

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Entities are required under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 740 to recognize the accounting impacts of a tax law change, including the impacts of a change in tax rates on deferred tax assets and liabilities, in the period including the date of the tax law enactment. The Securities and Exchange Commission (SEC) staff issued guidance in Staff Accounting Bulletin No. 118 *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* (SAB 118) that supplements the accounting requirements of ASC Topic 740 if elements of the TCJA assessment are not complete, and provides for up to a one year period to finalize the required accounting. Xcel Energy has estimated the effects of the TCJA, which have been reflected in the Dec. 31, 2017 financial statements. Issuance of U.S. Treasury regulations interpreting the TCJA, other U.S. Treasury and IRS guidance or interpretations of the application of ASC Topic 740 may result in changes to these estimates.

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

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

- \$1.1 billion (\$1.5 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21 percent federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- \$133 million and \$56 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;
- \$19 million of total estimated income tax expense related to the federal tax reform implementation, and a \$5 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

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

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

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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

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

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. The IRS proposed an adjustment to the federal tax loss carryback claims that would have resulted in \$14 million of income tax expense for the 2009 through 2011 claims, and the 2013 through 2015 claims. In the fourth quarter of 2015, the IRS forwarded the issue to the Office of Appeals (“Appeals”). In the third quarter of 2017, Xcel Energy and Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. As of Dec. 31, 2017, the case has been forwarded to the Joint Committee on Taxation.

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

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2017, NSP-Minnesota’s earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2009. In 2016, the state of Minnesota began an audit of years 2010 through 2014. As of Dec. 31, 2017, Minnesota had not proposed any material adjustments.

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

Uncertainty in Income Taxes — The FERC has not fully adopted the accounting guidance for uncertainty in income taxes. Accordingly, NSP-Minnesota has recorded its unrecognized tax benefits for temporary adjustments, including NOL and tax credit carryforwards, in accounts established for accumulated deferred income taxes.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Unrecognized tax benefit — Permanent tax positions	\$ 10.2	\$ 21.5
Unrecognized tax benefit — Temporary tax positions	7.9	39.3
Total unrecognized tax benefit	\$ 18.1	\$ 60.8

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

(Millions of Dollars)	2017	2016
Balance at Jan. 1	\$ 60.8	\$ 55.4
Additions based on tax positions related to the current year	2.7	3.7
Reductions based on tax positions related to the current year	(1.7)	(0.2)
Additions for tax positions of prior years	5.7	3.9
Reductions for tax positions of prior years	(49.4)	(2.0)
Balance at Dec. 31	\$ 18.1	\$ 60.8

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
NOL and tax credit carryforwards	\$ (12.8)	\$ (19.3)

It is reasonably possible that NSP-Minnesota's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS Appeals progresses and audit resumes, the Minnesota audit progresses, and other state audits resume. As the IRS Appeals and Minnesota audit progresses, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$7 million.

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

(Millions of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Payable for interest related to unrecognized tax benefits at Jan. 1	\$ (2.0)	\$ (0.2)
Interest income (expense) income related to unrecognized tax benefits	1.1	(1.8)
Payable for interest related to unrecognized tax benefits at Dec. 31	\$ (0.9)	\$ (2.0)

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Millions of Dollars)	2017	2016
Federal NOL carryforward	\$ 638	\$ 940
Federal tax credit carryforwards	306	232
State NOL carryforwards	296	265
State tax credit carryforwards, net of federal detriment	92	68
Valuation allowances for state credit carryforwards, net of federal detriment	(82)	(60)

The federal carryforward periods expire between 2021 and 2037. The state carryforward periods expire between 2019 and 2035.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2017	2016 (b)
Federal statutory rate	35.0%	35.0%
State income tax on pretax income, net of federal tax effect	5.8%	5.8%
Increases (decreases) in tax from:		
Wind production tax credits recognized	(11.4)	(8.2)
Other tax credits recognized, net of federal income tax expense	(1.1)	(0.8)
Tax reform	2.7	—
Regulatory differences - effects of rate changes ^(a)	(0.1)	(0.1)
Regulatory differences - other utility plant items	(0.2)	(0.2)
Other, net	(1.8)	—
Effective income tax rate	28.9%	31.5%

(a) The amortization of excess deferred taxes.

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

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

(Thousands of Dollars)	2017	2016
Current federal tax expense	\$ 29,810	\$ 19,338
Current state tax expense	14,747	9,308
Current change in unrecognized tax (benefit) expense	(11,315)	1,356
Deferred federal tax expense	121,490	142,328
Deferred state tax expense	46,618	53,908
Deferred investment tax credits	(1,648)	(1,663)
Rounding	1	—
Total income tax expense	\$ 199,703	\$ 224,575

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	2017	2016
Deferred tax (benefit) expense excluding items below	\$ (1,201,475)	\$ 225,151
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	1,369,948	(28,692)
Tax expense allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(365)	(223)
Deferred tax expense	<u>\$ 168,108</u>	<u>\$ 196,236</u>

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

(Thousands of Dollars)	2017	2016
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 2,577,662	\$ 3,604,910
Regulatory assets	(259,406)	154,805
Pension expense	54,190	64,223
Other	18,227	22,879
Total deferred tax liabilities	<u>\$ 2,390,673</u>	<u>\$ 3,846,817</u>
Deferred tax assets:		
Tax credit carryforward	\$ 315,891	\$ 239,610
Difference between book and tax bases of property	304,511	304,635
NOL carryforward	156,507	350,115
Other employee benefits	37,320	57,220
Deferred investment tax credits	6,839	10,663
Rate refund	6,602	21,094
Regulatory liabilities	(95,518)	9,188
Other	50,947	45,243
Total deferred tax assets	<u>\$ 783,099</u>	<u>\$ 1,037,768</u>
Net deferred tax liability	<u>\$ 1,607,574</u>	<u>\$ 2,809,049</u>

6. Benefit Plans and Other Postretirement Benefits

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Xcel Energy, which includes NSP-Minnesota, offers various benefit plans to its employees. Approximately 62 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2017, NSP-Minnesota had 1,858 bargaining employees covered under a collective-bargaining agreement, which expires in December 2019. NSP-Minnesota also had an additional 248 nuclear operation bargaining employees covered under several collective-bargaining agreements. These agreements expire in 2018 and 2019.

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

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

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

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

Specific valuation methods include the following:

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

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

Investments in commingled funds, equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with a few days' notice to annually with 90 days' notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Depending on the fund, unscheduled distributions from real estate investments may require approval of the fund or may be redeemed with proper notice, which is typically quarterly with 45-90 days' notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity.

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

Derivative Instruments — Fair values for foreign currency derivatives are determined using pricing models based on the prevailing forward exchange rate of the underlying currencies. The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Pension Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides unfunded, nonqualified benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions attributable to NSP-Minnesota's funded by NSP-Minnesota's operating cash flows. The total obligations of the SERP and nonqualified plan as of Dec. 31, 2017 and 2016 were \$37 million and \$44 million, respectively, of which \$5 million and \$6 million were attributable to NSP-Minnesota. In 2017 and 2016, Xcel Energy recognized net benefit cost for financial reporting for the SERP and nonqualified plans of \$5 million and \$8 million, respectively, of which \$1 million was attributable to NSP-Minnesota in both years.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to NSP-Minnesota will be supplemented by NSP-Minnesota's operating cash flows as determined necessary. For more information regarding the funding of rabbi trusts, see Note 7 to the financial statements. Also in 2016, Xcel Energy amended the deferred compensation plan to provide eligible participants the ability to diversify deferred settlements of equity awards, other than time-based equity awards, into various fund options.

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

- Investment returns in 2017 were above the assumed level of 7.10 percent;
- Investment returns in 2016 were below the assumed level of 7.10 percent; and
- In 2018, NSP-Minnesota's expected investment-return assumption is 7.10 percent.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	2017	2016
Domestic and international equity securities	38%	40%
Long-duration fixed income and interest rate swap securities	23	23
Short-to-intermediate fixed income securities	21	16
Alternative investments	16	19
Cash	2	2
Total	100%	100%

The ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

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

(Thousands of Dollars)	Dec. 31, 2017				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 53,427	\$ —	\$ —	\$ —	\$ 53,427
Commingled funds:					
U.S. equity funds	144,278	—	—	—	144,278
Non U.S. equity funds	25,753	—	—	55,986	81,739
U.S. corporate bond funds	92,674	—	—	—	92,674
Emerging market equity funds	—	—	—	88,355	88,355
Emerging market debt funds	21,116	—	—	46,742	67,858
Private equity investments	—	—	—	23,660	23,660
Real estate	—	—	—	54,863	54,863
Other commingled funds	1,362	—	—	32,786	34,148
Debt securities:					
Government securities	—	80,342	—	—	80,342
U.S. corporate bonds	—	67,205	—	—	67,205
Non U.S. corporate bonds	—	11,421	—	—	11,421
Equity securities:					
U.S. equities	32,111	—	—	—	32,111
Other	(8,718)	986	—	153	(7,579)
Total	\$ 362,003	\$ 159,954	\$ —	\$ 302,545	\$ 824,502

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Dec. 31, 2016					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 25,929	\$ —	\$ —	\$ —	\$ 25,929
Commingled funds:					
U.S. equity funds	140,973	—	—	—	140,973
Non U.S. equity funds	48,755	—	—	58,863	107,618
U.S. corporate bond funds	69,652	—	—	—	69,652
Emerging market equity funds	—	—	—	56,460	56,460
Emerging market debt funds	23,163	—	—	24,928	48,091
Commodity funds	—	—	—	5,854	5,854
Private equity investments	—	—	—	30,621	30,621
Real estate	—	—	—	53,373	53,373
Other commingled funds	—	—	—	57,611	57,611
Debt securities:					
Government securities	—	84,082	—	—	84,082
U.S. corporate bonds	—	62,091	—	—	62,091
Non U.S. corporate bonds	—	9,966	—	—	9,966
Mortgage-backed securities	—	1,674	—	—	1,674
Asset-backed securities	—	793	—	—	793
Equity securities:					
U.S. equities	27,775	—	—	—	27,775
Other	—	633	—	—	633
Total	\$ 336,247	\$ 159,239	\$ —	\$ 287,710	\$ 783,196

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	2017	2016
Accumulated Benefit Obligation at Dec. 31	\$ 969,027	\$ 971,544

Change in Projected Benefit Obligation:

Obligation at Jan. 1	\$ 1,036,508	\$ 1,023,123
Service cost	27,831	28,307
Interest cost	40,707	45,431
Plan amendments	(4,464)	1,411
Actuarial loss	64,137	46,992
Benefit payments ^(a)	(129,580)	(108,756)
Obligation at Dec. 31	\$ 1,035,139	\$ 1,036,508

(Thousands of Dollars)

2017

2016

Change in Fair Value of Plan Assets:

Fair value of plan assets at Jan. 1	\$ 783,196	\$ 800,243
Actual return on plan assets	110,145	42,279
Employer contributions	60,741	49,430
Benefit payments ^(a)	(129,580)	(108,756)
Fair value of plan assets at Dec. 31	\$ 824,502	\$ 783,196

(Thousands of Dollars)

2017

2016

Funded Status of Plans at Dec. 31:

Funded status ^(b)	\$ (210,637)	\$ (253,312)
------------------------------	--------------	--------------

(a) 2017 amount includes approximately \$96 million of lump-sum benefit payments used in the determination of a settlement charge.

(b) Amounts are recognized in other noncurrent liabilities on NSP-Minnesota's balance sheet.

(Thousands of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 545,298	\$ 618,675
Prior service (credit) cost	(1,304)	5,185
Total	\$ 543,994	\$ 623,860

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Other regulatory assets	\$ 543,994	\$ 623,860
Measurement date	Dec. 31, 2017	Dec. 31, 2016
	<u>2017</u>	<u>2016</u>
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	3.63%	4.13%
Expected average long-term increase in compensation level	3.75%	3.75%
Mortality table	RP-2014	RP-2014

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

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2016 through 2018 to meet minimum funding requirements.

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

- \$150 million in January 2018, of which \$63 million was attributable to NSP-Minnesota;
- \$162 million in 2017, of which \$61 million was attributable to NSP-Minnesota; and
- \$125 million in 2016, of which \$49 million was attributable to NSP-Minnesota.

For future years, Xcel Energy and NSP-Minnesota anticipate contributions will be made as necessary.

Plan Amendments — Xcel Energy, which includes NSP-Minnesota, amended the Xcel Energy Pension Plan in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans. In 2016, the Xcel Energy Pension Plan was amended to change the discount rate basis for lump-sum conversion to annuity participants and annuity conversion to lump-sum participants.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Benefit Costs — The components of NSP-Minnesota’s net periodic pension cost were:

(Thousands of Dollars)	2017	2016
Service cost	\$ 27,831	\$ 28,307
Interest cost	40,707	45,431
Expected return on plan assets	(60,066)	(60,944)
Amortization of prior service cost	1,060	936
Amortization of net loss	39,609	36,777
Settlement charge (a)	48,171	—
Net periodic pension cost	97,312	50,507
Costs not recognized due to effects of regulation	(72,221)	(20,865)
Net benefit cost recognized for financial reporting	\$ 25,091	\$ 29,642

(a) A settlement charge is required when the amount of 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 the fourth quarter of 2017 as a result of lump-sum distributions during the 2017 plan year, NSP-Minnesota recorded a total pension settlement charge of \$48 million, which was not recognized due to the effects of rate making.

	2017		2016	
Significant Assumptions Used to Measure Costs:				
Discount rate	4.13	%	4.66	%
Expected average long-term increase in compensation level	3.75		4.00	
Expected average long-term rate of return on assets	7.10		7.10	

In addition to the benefit costs in the table above, for the pension plans sponsored by Xcel Energy, Inc., costs are allocated to NSP-Minnesota based on Xcel Energy Services Inc. employees’ labor costs. The amount allocated to NSP-Minnesota was \$19 million and \$11 million in 2017 and 2016, respectively. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2018 pension cost calculations is 7.10 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Minnesota, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover substantially all employees. The expense to these plans for NSP-Minnesota was approximately \$12 million in both 2017 and 2016.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees. NSP-Minnesota discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs.

Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. These assets are invested in a manner consistent with the investment strategy for the pension plan.

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

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

Xcel Energy Inc. and NSP-Minnesota base investment-return assumptions for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. Assumptions and target allocations are determined at the master trust level. The investment mix at each of Xcel Energy Inc.'s utility subsidiaries may vary from the investment mix of the total asset portfolio. The assets are invested in a portfolio according to Xcel Energy Inc.'s and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Market volatility is not considered to be a material factor in postretirement health care costs.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	Dec. 31, 2017				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 417	\$ —	\$ —	\$ —	\$ 417
Insurance contracts	—	706	—	—	706
Commingled funds:					
U.S. equity funds	1,052	—	—	—	1,052
U.S. fixed income funds	486	—	—	—	486
Emerging market debt funds	574	—	—	—	574
Debt securities:					
Government securities	—	820	—	—	820
U.S. corporate bonds	—	897	—	—	897
Non U.S. corporate bonds	—	304	—	—	304
Asset-backed securities	—	332	—	—	332
Mortgage-backed securities	—	490	—	—	490
Equity securities:					
Non U.S. equities	497	—	—	—	497
Other	—	15	—	—	15
Total	\$ 3,026	\$ 3,564	\$ —	\$ —	\$ 6,590

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Dec. 31, 2016				
	Level 1	Level 2	Level 3	Investments Measured at NAV	Total
Cash equivalents	\$ 172	\$ —	\$ —	\$ —	\$ 172
Insurance contracts	—	395	—	—	395
Commingled funds:					
U.S. equity funds	455	—	—	—	455
U.S. fixed income funds	227	—	—	—	227
Emerging market debt funds	254	—	—	—	254
Other commingled funds	—	—	—	459	459
Debt securities:					
Government securities	—	315	—	—	315
U.S. corporate bonds	—	521	—	—	521
Non U.S. corporate bonds	—	144	—	—	144
Asset-backed securities	—	158	—	—	158
Mortgage-backed securities	—	240	—	—	240
Equity securities:					
Non U.S. equities	342	—	—	—	342
Other	—	12	—	—	12
Total	\$ 1,450	\$ 1,785	\$ —	\$ 459	\$ 3,694

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	2017	2016
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 86,695	\$ 88,684
Service cost	144	123
Interest cost	3,415	3,925
Medicare subsidy reimbursements	14	29
Plan participants' contributions	411	451
Actuarial loss	5,897	1,880
Benefit payments	(7,696)	(8,397)
Obligation at Dec. 31	\$ 88,880	\$ 86,695
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 3,694	\$ 2,969
Actual return on plan assets	38	7
Plan participants' contributions	411	451
Employer contributions	10,143	8,664
Benefit payments	(7,696)	(8,397)
Fair value of plan assets at Dec. 31	\$ 6,590	\$ 3,694
Funded Status of Plans at Dec. 31:		
Funded status	\$ (82,290)	\$ (83,001)
Other noncurrent liabilities	(82,290)	(83,001)
Net postretirement amounts recognized on balance sheets	\$ (82,290)	\$ (83,001)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	\$ 45,353	\$ 41,306
Prior service credit	(15,397)	(18,433)
Total	\$ 29,956	\$ 22,873

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	2017	2016
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Other regulatory assets	\$ 28,013	\$ 21,386
Deferred income taxes	546	606
Net-of-tax accumulated OCI	1,397	881
Total	\$ 29,956	\$ 22,873
Measurement date	Dec. 31, 2017	Dec. 31, 2016
	2017	2016
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	3.62%	4.13%
Mortality table	RP 2014	RP 2014
Health care costs trend rate — initial Pre-65	7.00%	5.50%
Health care costs trend rate — initial Post-65	5.50%	5.50%

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

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

(Thousands of Dollars)	One Percentage Point	
	Increase	Decrease
Accumulated postretirement benefit obligation	\$ 8,627	\$ (7,300)
Service and interest components	373	(315)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy, which includes NSP-Minnesota, contributed \$20 million and \$18 million during 2017 and 2016, respectively, of which \$10 million and \$9 million were attributable to NSP-Minnesota. Xcel Energy expects to contribute approximately \$12 million during 2018, of which \$8 million is attributable to NSP-Minnesota.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Benefit Costs — The components of NSP-Minnesota’s net periodic postretirement benefit costs were:

(Thousands of Dollars)	2017	2016
Service cost	\$ 144	\$ 123
Interest cost	3,415	3,925
Expected return on plan assets	(214)	(172)
Amortization of prior service credit	(3,036)	(3,036)
Amortization of net loss	2,026	1,603
Net periodic postretirement benefit cost	\$ 2,335	\$ 2,443
	<u>2017</u>	<u>2016</u>

Significant Assumptions Used to Measure Costs:

Discount rate	4.13%	4.65%
Expected average long-term rate of return on assets	5.80	5.80

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

Projected Benefit Payments

The following table lists NSP-Minnesota’s projected benefit payments for the pension and postretirement benefit plans:

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2018	\$ 113,726	\$ 7,939	\$ 8	\$ 7,931
2019	85,533	7,576	7	7,569
2020	81,410	7,421	8	7,413
2021	81,329	7,058	5	7,053
2022	81,221	6,630	5	6,625
2023-2027	365,595	28,677	41	28,636

Multiemployer Plans

NSP-Minnesota contributes 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 sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2017 and 2016. The average number of NSP-Minnesota union employees covered by the multiemployer pension plans decreased to approximately 562 in 2017 from approximately 700 in 2016. There were no other significant changes to the nature or magnitude of the participation of NSP-Minnesota in multiemployer plans for the years presented:

(Thousands of Dollars)	2017	2016
Multiemployer plan contributions:		
Pension	11,914	13,843
Other postretirement benefits	72	86
Total	11,986	13,929

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 and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

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

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

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

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value (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, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds may be redeemed for NAV with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, 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 NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of NSP-Minnesota.

Non-Derivative Instruments Fair Value Measurements

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. 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 of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, 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, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Unrealized gains for the nuclear decommissioning fund were \$560 million and \$379 million as of Dec. 31, 2017 and 2016, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were \$7 million and \$47 million as of Dec. 31, 2017 and 2016, respectively.

The following tables present the cost and fair value of NSP-Minnesota's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund as of Dec. 31, 2017 and 2016:

(Thousands of Dollars)	Dec. 31, 2017						
	Cost	Fair Value				Investments Measured at NAV	Total
		Level 1	Level 2	Level 3	Level 3		
Nuclear decommissioning fund							
Cash equivalents	\$ 28,741	\$ 28,741	\$ —	\$ —	\$ —	\$ —	\$ 28,741
Commingled funds:							
Non U.S. equities	263,694	216,551	—	—	89,857	—	306,408
Emerging market debt funds	156,057	—	—	—	166,375	—	166,375
Private equity investments	141,413	—	—	—	198,037	—	198,037
Real estate	130,787	—	—	—	201,842	—	201,842
Other commingled funds	9,340	6,286	—	—	2,975	—	9,261
Debt securities:							
Government securities	67,760	—	69,413	—	—	—	69,413
U.S. corporate bonds	319,809	—	322,129	—	—	—	322,129
Non U.S. corporate bonds	50,121	—	50,102	—	—	—	50,102
Equity securities:							
U.S. equities	271,166	556,974	—	—	—	—	556,974
Non U.S. equities	151,961	233,999	—	—	—	—	233,999
Total	\$ 1,590,849	\$ 1,042,551	\$ 441,644	\$ —	\$ 659,086	\$ —	\$ 2,143,281

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Dec. 31, 2016					
	Cost	Fair Value			Investments Measured at NAV	Total
		Level 1	Level 2	Level 3		
Nuclear decommissioning fund						
Cash equivalents	\$ 20,379	\$ 20,379	\$ —	\$ —	\$ —	\$ 20,379
Commingled funds:						
Non U.S. equities	260,877	133,126	—	—	112,233	245,359
Emerging market debt funds	93,597	—	—	—	97,543	97,543
Commodity funds	106,571	—	—	—	92,091	92,091
Private equity investments	132,190	—	—	—	190,462	190,462
Real estate	128,630	—	—	—	187,647	187,647
Other commingled funds	151,048	—	—	—	159,489	159,489
Debt securities:						
Government securities	32,764	—	31,965	—	—	31,965
U.S. corporate bonds	104,913	—	105,772	—	—	105,772
Non U.S. corporate bonds	21,751	—	21,672	—	—	21,672
Municipal bonds	13,609	—	13,786	—	—	13,786
Mortgage-backed securities	2,785	—	2,816	—	—	2,816
Equity securities:						
U.S. equities	270,779	473,400	—	—	—	473,400
Non U.S. equities	189,100	218,381	—	—	—	218,381
Total	\$ 1,528,993	\$ 845,286	\$ 176,011	\$ —	\$ 839,465	\$ 1,860,762

For the year ended Dec. 31, 2017 and 2016 there were no Level 3 nuclear decommissioning fund investments and no transfers of amounts between levels.

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, as of Dec. 31, 2017:

(Thousands of Dollars)	Final Contractual Maturity				Total
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	
Government securities	\$ —	\$ 2,644	\$ —	\$ 66,769	\$ 69,413
U.S. corporate bonds	5,000	84,617	174,316	58,196	322,129
Non U.S. corporate bonds	—	14,634	31,144	4,354	50,132
Debt securities	\$ 5,000	\$ 101,895	\$ 205,460	\$ 129,319	\$ 441,674

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Rabbi Trusts

In June 2016, NSP-Minnesota established a rabbi trust to provide partial funding for future deferred compensation plan distributions. The following table presents the cost and fair value of the assets held in rabbi trust at Dec. 31, 2017 and 2016:

(Thousands of Dollars)	Dec. 31, 2017				
	Cost	Fair Value			Total
		Level 1	Level 2	Level 3	
Rabbi Trusts (a)					
Cash equivalents	\$ 783	\$ 783	\$ —	\$ —	\$ 783
Mutual funds	10,332	11,283	—	—	11,283
Total	\$ 11,115	\$ 12,066	\$ —	\$ —	\$ 12,066
(Thousands of Dollars)	Dec. 31, 2016				
	Cost	Fair Value			Total
		Level 1	Level 2	Level 3	
Rabbi Trusts (a)					
Cash equivalents	\$ 7,459	\$ 7,459	\$ —	\$ —	\$ 7,459
Mutual funds	1,663	1,901	—	—	1,901
Total	\$ 9,122	\$ 9,360	\$ —	\$ —	\$ 9,360

(a) Reported in other investments on the balance sheet.

Derivative Instruments Fair Value Measurements

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

At Dec. 31, 2017, accumulated other comprehensive losses related to interest rate derivatives included \$0.8 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 — NSP-Minnesota 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. NSP-Minnesota's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Commodity Derivatives — NSP-Minnesota 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.

At Dec. 31, 2017, NSP-Minnesota had various vehicle fuel contracts designated as cash flow hedges extending through December 2018. NSP-Minnesota enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. NSP-Minnesota recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2017 and 2016.

At Dec. 31, 2017, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included \$0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

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

(Amounts in Thousands) (a)(b)	2017	2016
Megawatt hours (MWh) of electricity	41,711	37,805
Million British thermal units (MMBtu) of natural gas	23,829	79,520
Gallons of vehicle fuel	240	—

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of NSP-Minnesota's own credit risk when determining the fair value of derivative liabilities, the impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. At Dec. 31, 2017, six of NSP-Minnesota's 10 most significant counterparties for these activities, comprising \$38.7 million or 54 percent of this credit exposure, had investment grade credit ratings from Standard & Poor's Rating Services, Moody's Investor Services or Fitch Ratings. Three of the 10 most significant counterparties, comprising \$15.2 million or 21 percent of this credit exposure at Dec. 31, 2017, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. Another of these significant counterparties, comprising \$0.9 million or 1 percent of this credit exposure, had credit quality less than investment grade, based on ratings from internal analysis. Nine of these significant counterparties are municipal or cooperative electric entities, or other utilities.

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

(Thousands of Dollars)	2017	2016
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ (18,208)	\$ (19,090)
After-tax net unrealized gains related to derivatives accounted for as hedges	85	5
After-tax net realized losses on derivative transactions reclassified into earnings	931	877
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	<u>\$ (17,192)</u>	<u>\$ (18,208)</u>

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

(Thousands of Dollars)	Year Ended Dec. 31, 2017					
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income	
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)		
Derivatives designated as cash flow hedges						
Interest rate	\$ —	\$ —	\$ 1,571 ^(a)	\$ —	\$ —	
Vehicle fuel and other commodity	143	—	(38) ^(b)	—	—	
Total	<u>\$ 143</u>	<u>\$ —</u>	<u>\$ 1,533</u>	<u>\$ —</u>	<u>\$ —</u>	
Other derivative instruments						
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 9,393 ^(c)	
Electric commodity	—	9,288	—	(13,794) ^(d)	—	
Natural gas commodity	—	(1,862)	—	972 ^(e)	(1,219) ^(e)	
Total	<u>\$ —</u>	<u>\$ 7,426</u>	<u>\$ —</u>	<u>\$ (12,822)</u>	<u>\$ 8,174</u>	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(Thousands of Dollars)	Year Ended Dec. 31, 2016				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	\$ —	\$ —	\$ 1,392 ^(a)	\$ —	\$ —
Vehicle fuel and other commodity	8	—	104 ^(b)	—	—
Total	\$ 8	\$ —	\$ 1,496	\$ —	\$ —
Other derivative instruments					
Commodity trading	\$ —	\$ —	\$ —	\$ —	\$ 2,825 ^(c)
Electric commodity	—	14,459	—	(6,090) ^(d)	—
Natural gas commodity	—	(1,235)	—	4,031 ^(e)	(2,166) ^(e)
Total	\$ —	\$ 13,224	\$ —	\$ (2,059)	\$ 659

^(a) Amounts are recorded to interest charges.

^(b) Amounts are recorded to operating expenses.

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

^(d) Amounts are 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.

^(e) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

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

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies or for cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2017 and 2016, there were no derivative instruments in a material liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain a adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to a adequate assurance clauses in derivative contracts as of Dec. 31, 2017 and 2016.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	Dec. 31, 2017					
	Fair Value			Total Fair Value	Counterparty Netting (b)	
	Level 1	Level 2	Level 3		Total	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	\$ —	\$ 107	\$ —	\$ 107	\$ —	\$ 107
Other derivative instruments:						
Commodity trading	1,691	17,144	142	18,977	(11,744)	7,233
Electric commodity	—	—	17,581	17,581	(425)	17,156
Natural gas commodity	—	77	—	77	—	77
Total current derivative assets	<u>\$ 1,691</u>	<u>\$ 17,328</u>	<u>\$ 17,723</u>	<u>\$ 36,742</u>	<u>\$ (12,169)</u>	<u>24,573</u>
PPAs (a)						657
Current derivative instruments						<u>\$ 25,230</u>
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	\$ —	\$ 29,121	\$ 5,363	\$ 34,484	\$ (6,502)	\$ 27,982
Total noncurrent derivative assets	<u>\$ —</u>	<u>\$ 29,121</u>	<u>\$ 5,363</u>	<u>\$ 34,484</u>	<u>\$ (6,502)</u>	<u>27,982</u>
PPAs (a)						120
Noncurrent derivative instruments						<u>\$ 28,102</u>
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ 1,713	\$ 13,853	\$ —	\$ 15,566	\$ (11,974)	\$ 3,592
Electric commodity	—	—	425	425	(425)	—
Total current derivative liabilities	<u>\$ 1,713</u>	<u>\$ 13,853</u>	<u>\$ 425</u>	<u>\$ 15,991</u>	<u>\$ (12,399)</u>	<u>3,592</u>
PPAs (a)						14,105
Current derivative instruments						<u>\$ 17,697</u>
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ —	\$ 22,163	\$ —	\$ 22,163	\$ (9,334)	\$ 12,829
Total noncurrent derivative liabilities	<u>\$ —</u>	<u>\$ 22,163</u>	<u>\$ —</u>	<u>\$ 22,163</u>	<u>\$ (9,334)</u>	<u>12,829</u>
PPAs (a)						89,913
Noncurrent derivative instruments						<u>\$ 102,742</u>

(a) 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

(b) NSP-Minnesota 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, 2017. At Dec. 31, 2017, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$3.1 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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

(Thousands of Dollars)	Dec. 31, 2016					
	Fair Value			Total Fair Value	Counterparty Netting (b)	
	Level 1	Level 2	Level 3		Total	Total
Current derivative assets						
Other derivative instruments:						
Commodity trading	\$ 12,053	\$ 8,651	\$ —	\$ 20,704	\$ (15,500)	\$ 5,204
Electric commodity	—	—	15,997	15,997	(677)	15,320
Natural gas commodity	—	912	—	912	—	912
Total current derivative assets	\$ 12,053	\$ 9,563	\$ 15,997	\$ 37,613	\$ (16,177)	21,436
PPAs (a)						592
Current derivative instruments						\$ 22,028
Noncurrent derivative assets						
Other derivative instruments:						
Commodity trading	\$ 100	\$ 31,029	\$ —	\$ 31,129	\$ (7,323)	\$ 23,806
Total noncurrent derivative assets	\$ 100	\$ 31,029	\$ —	\$ 31,129	\$ (7,323)	23,806
PPAs (a)						872
Noncurrent derivative instruments						\$ 24,678
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ 12,397	\$ 5,964	\$ —	\$ 18,361	\$ (15,837)	\$ 2,524
Electric commodity	—	—	677	677	(677)	—
Total current derivative liabilities	\$ 12,397	\$ 5,964	\$ 677	\$ 19,038	\$ (16,514)	2,524
PPAs (a)						14,082
Current derivative instruments						\$ 16,606
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	\$ 89	\$ 23,424	\$ —	\$ 23,513	\$ (10,727)	\$ 12,786
Total noncurrent derivative liabilities	\$ 89	\$ 23,424	\$ —	\$ 23,513	\$ (10,727)	12,786
PPAs (a)						104,018
Noncurrent derivative instruments						\$ 116,804

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- (a) During 2006, NSP-Minnesota qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.
- (b) NSP-Minnesota 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, 2016. At Dec. 31, 2016, derivative assets and liabilities include no obligations to return cash collateral and rights to reclaim cash collateral of \$3.7 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2017 and 2016:

(Thousands of Dollars)	Year Ended Dec. 31	
	2017	2016
Balance at Jan. 1	\$ 15,320	\$ 12,970
Purchases	40,614	27,976
Settlements	(41,718)	(47,192)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings ^(a)	5,505	(2)
Net gains recognized as regulatory assets and liabilities	2,940	21,568
Balance at Dec. 31	\$ 22,661	\$ 15,320

- (a) These amounts relate to commodity derivatives held at the end of the period.

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

Fair Value of Long-Term Debt

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

(Thousands of Dollars)	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	\$ 4,978,265	\$ 5,601,919	\$ 4,883,071	\$ 5,310,925

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

8. Rate Matters

Tax Reform - Regulatory Proceedings

The specific impacts of the TCJA on retail customer rates are subject to regulatory approval. NSP-Minnesota is in the process of quantifying the rate impacts of the TCJA and addressing these impacts in its recently concluded proceedings focused on retail base rate impacts.

A docket has been opened in Minnesota. NSP-Minnesota provided a filing to the MPUC in March 2018, which estimated the impact of the TCJA on 2018 revenue requirements (including base rates and riders) as an overall reduction of approximately \$133 million and \$8 million for electric and natural gas, respectively. The filing also proposed potential options for delivering tax reform benefits to customers that may be used to provide different short-term or long-term impacts.

Dockets have also been opened in North Dakota and South Dakota. In February 2018, NSP-Minnesota provided the North Dakota Public Service Commission (NDPSC) a preliminary quantification of the impact of the TCJA on electric and natural gas revenue requirements. NSP-Minnesota proposed multi-year moratoriums on electric and natural gas rate case filings. NSP-Minnesota also filed comments with the South Dakota Public Utility Commission (SDPUC) and proposed using the reduced revenue requirements from the TCJA to defer planned future rate filings.

Pending and Recently Concluded Regulatory Proceedings — MPUC

Minnesota 2016 Multi-Year Electric Rate Case — In June 2017, the MPUC issued a written order approving an estimated total rate increase of approximately \$240 million over the four-year period covering 2016-2019.

Key terms:

- Four-year period covering 2016-2019;
- Annual sales true-up with decoupling subject to a 3 percent cap on surcharges;
 - In February 2018, NSP-Minnesota reported the 2017 sales true-up and revenue decoupling surcharge amounts of \$22 million and \$27 million, respectively, to be collected beginning April 1, 2018 through March 31, 2019.
- Return on equity (ROE) of 9.2 percent and an equity ratio of 52.5 percent;
- Nuclear related costs will not be considered provisional;
- Continued use of all existing electric riders, however no new electric riders may be utilized during the four-year term;
- Deferral of incremental 2016 property tax expense above a fixed threshold to 2018 and 2019;
- Four-year stay out provision for rate cases;
- Property tax true-up mechanism for 2017-2019; and
- Capital expenditure true-up mechanism for 2016-2019.

(Millions of Dollars, incremental)	2016	2017	2018	2019	Total
Revenues	\$ 75	\$ 55	\$ —	\$ 50	\$ 180
NSP-Minnesota's sales true-up	60	—	—	—	60
Total rate impact	\$ 135	\$ 55	\$ —	\$ 50	\$ 240

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

2017 and 2018 Transmission Cost Recovery (TCR) Filing — In November 2017, NSP-Minnesota submitted a TCR filing with the MPUC, requesting a combined recovery of approximately \$110 million of transmission investment costs not included in electric base rates for 2017 and 2018. In accordance with NSP-Minnesota’s most recent electric rate case, three CapX2020 transmission projects currently included in the TCR rider remain in the rider through the multi-year plan period. NSP-Minnesota has also proposed recovery of one additional project related to grid modernization. An MPUC decision is expected in 2018.

Electric, Purchased Gas and Resource Adjustment Clauses

CIP and CIP Rider — CIP expenses are recovered through base rates and a rider that is adjusted annually. The estimated electric and natural gas incentives for 2017 are expected to be \$32 million and \$3 million, respectively, based on the approved savings goals in NSP-Minnesota’s CIP Triennial Plan. The plan sets an annual electric goal of saving the equivalent of 1.5 percent of the volume of electric energy sales and an annual natural gas goal of saving 1.0 percent of the volume of gas energy sales. In 2017 the MPUC approved the following for NSP-Minnesota:

- The 2016 CIP electric and natural gas financial incentives totaling \$48 million and \$6 million, respectively; and
- The proposed 2017 electric and natural gas CIP riders with estimated 2017 recovery of \$59 million of electric CIP expenses and \$18 million of natural gas CIP expenses. The proposed recovery through the riders is in addition to an estimated \$89 million and \$4 million through electric and gas base rates, respectively.

Gas Utility Infrastructure Cost (GUIC) Rider — In February 2018, the MPUC approved a 2017 revenue requirement of approximately \$20 million for GUIC investments. New rates went into effect in March 2018. In November 2017, NSP-Minnesota filed the 2018 GUIC rider with the MPUC requesting recovery of approximately \$28 million from Minnesota gas utility customers. Costs in both filings include funding for pipeline assessments as well as deferred costs from NSP-Minnesota’s existing sewer separation and pipeline integrity management programs. The MPUC is currently considering the 2018 petition.

Annual Automatic Adjustment of Fuel Clause Charges — In May 2017, the MPUC voted to disallow approximately \$4 million of replacement energy costs for the PI nuclear facility outages allocated to the Minnesota jurisdiction in 2015. This disallowance was recognized in the second quarter of 2017. In December 2017, the MPUC issued an order to hold utilities responsible for incremental costs of replacement power incurred due to unplanned outages under certain circumstances. In January 2018, NSP-Minnesota filed a petition for clarification of the order. The outcome of the petition is uncertain.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Pending Regulatory Proceedings — FERC

MISO ROE Complaints/ROE Adder — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners (TOs), including NSP-Minnesota and NSP-Wisconsin. The complaint argued for a reduction in the ROE in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, and the removal of ROE adders (including those for RTO membership), effective Nov. 12, 2013.

In December 2015, an administrative law judge (ALJ) recommended the FERC approve a base ROE of 10.32 percent for the MISO TOs. The ALJ found the existing 12.38 percent ROE to be unjust and unreasonable. The recommended 10.32 percent ROE applied a FERC ROE policy adopted in a June 2014 order (Opinion 531). The FERC approved the ALJ recommended 10.32 percent base ROE in an order issued in September 2016. This ROE would be applicable for Nov. 12, 2013 to Feb. 11, 2015, and prospectively from the date of the FERC order. The total prospective ROE would be 10.82 percent, including a 50 basis point adder for RTO membership. Various parties requested rehearing of the September 2016 order. The requests are pending FERC action.

In February 2015, a second complaint seeking to reduce the MISO ROE from 12.38 percent to 8.67 percent prior to any adder was filed with the FERC, resulting in a second period of potential refund from Feb. 12, 2015 to May 11, 2016. In June 2016, the ALJ recommended a ROE of 9.7 percent, applying the methodology adopted by the FERC in Opinion 531. In April 2017, the D.C. Circuit vacated and remanded Opinion 531. It is unclear how the D.C. Circuit's opinion to vacate and remand Opinion 531 will affect the September 2016 FERC order or the timing and outcome of the second ROE complaint. In September 2017, certain MISO TOs (not including NSP-Minnesota and NSP-Wisconsin) filed a motion to dismiss the second ROE complaint. The motion to dismiss is pending FERC action.

As of Dec. 31, 2017, NSP-Minnesota has processed the refunds for the Nov. 12, 2013 to Feb. 11, 2015 complaint period based on the 10.32 percent ROE. NSP-Minnesota has also recognized a current refund liability consistent with the best estimate of the final ROE for the Feb. 12, 2015 to May 11, 2016 complaint period.

9. Commitments and Contingencies

Commitments

Capital Commitments — NSP-Minnesota has made commitments in connection with a portion of its projected capital expenditures. NSP-Minnesota's capital commitments primarily relate to wind project plans:

Upper Midwest Wind Projects — NSP-Minnesota has gained approval to build and own 1,150 MW of new wind generation in the Upper Midwest. NSP-Minnesota is also seeking approval from the MPUC to build and own the Dakota Range project, a 300 MW wind project in South Dakota.

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2018 and 2033. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas	Natural gas storage and transportation
2018	\$ 316	\$ 61	\$ 27	\$ 105
2019	52	118	2	95
2020	14	34	1	84
2021	1	85	1	82
2022	—	66	1	79
Thereafter	—	379	—	360
Total (a)	\$ 383	\$ 743	\$ 32	\$ 805

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

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

PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements and meet operating reserve obligations. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments. Capacity and energy payments are typically contingent on the independent power producing entity meeting contract obligations, including plant availability requirements. Contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs, accounted for as executory contracts, were payments for capacity of \$84 million and \$90 million in 2017 and 2016, respectively. At Dec. 31, 2017, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, are as follows:

(Millions of Dollars)	Capacity	Energy (a)
2018	\$ 53	\$ 93
2019	54	99
2020	53	106
2021	57	140
2022	61	155
Thereafter	172	367
Total (b)	\$ 450	\$ 960

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

(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

Leases — NSP-Minnesota leases a variety of equipment and facilities. These leases, primarily for office space, railcars, generating facilities, natural gas pipeline transportation, vehicles, aircraft and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations were approximately \$77 million and \$79 million for 2017 and 2016, respectively. These expenses include capacity payments for PPAs accounted for as operating leases of \$63 million in both 2017 and 2016 recorded to electric fuel and purchased power expenses.

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

(Millions of Dollars)	Operating Leases	PPA Operating Leases (a) (b)	Total Operating Leases
2018	\$ 8	\$ 66	\$ 74
2019	13	82	95
2020	7	95	102
2021	7	97	104
2022	7	98	105
Thereafter	43	746	789

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

(b) PPA operating leases contractually expire through 2039.

Guarantees — Under NSP-Minnesota's railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

(Millions of Dollars)	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	\$ 4.8	\$ —	2019	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Environmental Contingencies

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

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

MGP Sites

Fargo, N.D. MGP Site — In May 2015, underground pipes, tars and impacted soils were discovered in a right-of-way in Fargo, N.D. that appeared to be associated with a former MGP operated by NSP-Minnesota or prior companies. NSP-Minnesota removed impacted soils and other materials and commenced an investigation of the historic MGP and adjacent properties (the Fargo MGP Site). The North Dakota Department of Health approved NSP-Minnesota's proposed cleanup plan in January 2017, which involves targeted source removal of impacted soils and historic MGP infrastructure. It is anticipated that remediation activities will be performed in 2018. NSP-Minnesota has also initiated insurance recovery litigation in North Dakota. The U.S. District Court for the District of North Dakota agreed to the parties' request for a stay of the litigation until May 31, 2018.

NSP-Minnesota had recorded an estimated liability of \$16 million as of Dec. 31, 2017, and \$11 million as of Dec. 31, 2016, for the Fargo MGP Site. The current cost estimate for the remediation of the site is approximately \$23 million, of which approximately \$7 million has been spent. NSP-Minnesota has deferred Fargo MGP Site costs allocable to the North Dakota jurisdiction, or approximately 88 percent of all remediation costs, as approved by the NDPSC. In December 2017, NSP-Minnesota filed a request with the MPUC to defer post-2017 expenditures allocable to the Minnesota jurisdiction.

Other MGP, Landfill or Disposal Sites — NSP-Minnesota is currently involved in investigating and/or remediating several MGP, landfill or other disposal sites. NSP-Minnesota has identified seven sites where contamination is present and where investigation and/or remediation activities are currently underway. Other parties may have responsibility for some portion of the investigation and/or remediation activities underway. NSP-Minnesota anticipates that these investigation or remediation activities will continue through at least 2018. NSP-Minnesota had accrued \$3 million as of Dec. 31, 2017, and an immaterial amount as of Dec. 31, 2016, for all of these sites. There may be insurance recovery and/or recovery from other PRPs that will offset any costs incurred. NSP-Minnesota anticipates that any amounts spent will be fully recovered from customers.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Environmental Requirements

Water and Waste

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

Coal Ash Regulation — NSP-Minnesota’s operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the EPA published a final rule regulating the management, storage, and disposal of coal combustion residuals (CCRs) as a nonhazardous waste (CCR Rule). Industry and environmental non-governmental organizations sought judicial review of the final CCR Rule, but a final decision has not been issued in that litigation. The EPA announced in late 2017 its intent to revise the CCR Rule. It is anticipated that the EPA will publish the revised rule in the first quarter of 2018.

Under the CCR Rule, utilities were required to complete groundwater sampling around their CCR landfills and surface impoundments and to analyze the results by early 2018 to determine if there were any statistically significant increases (SSIs) above background levels of certain constituents in the groundwater. NSP-Minnesota has identified SSIs at one site. Going forward, NSP-Minnesota will either conduct additional groundwater sampling to determine whether another source besides plant operations is impacting groundwater and/or to determine if corrective action is needed.

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

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

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). NSP-Minnesota estimates the likely cost for complying with impingement requirements may be incurred between 2018 and 2027 and is approximately \$37 million. NSP-Minnesota believes at least six plants could be required by state regulators to make improvements to reduce entrainment. The exact total cost of the entrainment improvements is uncertain, but could be up to \$188 million. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

Air

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

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

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

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

Implementation of the National Ambient Air Quality Standard (NAAQS) for SO₂ — The EPA adopted a more stringent NAAQS for SO₂ in 2010 and evaluated areas in three phases. In December 2017, the EPA adopted a final rule that completed its initial designations of areas attaining or not attaining the standard. The EPA’s final actions designate all areas near NSP-Minnesota’s generating plants as meeting the SO₂ NAAQS.

Revisions to the NAAQS for Ozone — In 2015, the EPA revised the NAAQS for ozone by lowering the eight-hour standard from 75 parts per billion (ppb) to 70 ppb. In November 2017, the EPA published final designations of areas that meet the 2015 ozone standard. NSP-Minnesota meets the 2015 ozone standard in all areas where its generating units operate.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Asset Retirement Obligations

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

NSP-Minnesota has recognized AROs for the retirement costs of natural gas mains and lines and for the removal of electric transmission and distribution equipment, which consists of obligations associated with polychlorinated biphenyl, mineral oil, lithium batteries, mercury and street lighting lamps. The common general AROs include obligations related to storage tanks, radiation sources and office buildings.

For the nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and PI. See Note 10 for further discussion of nuclear obligations.

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

(Thousands of Dollars)	Beginning Balance Jan. 1, 2017	Liabilities Recognized	Liabilities Settled ^(a)	Accretion	Cash Flow Revisions ^(b)	Ending Balance Dec. 31, 2017 ^(c)
Electric plant						
Nuclear production decommissioning	\$ 2,249,322	\$ —	\$ —	\$ 113,785	\$ (489,474)	\$ 1,873,633
Wind production	90,106	—	—	4,047	—	94,153
Steam production ash containment	41,739	—	(3,443)	1,276	(668)	38,904
Steam and other production asbestos	26,731	—	(1,511)	1,080	(1,308)	24,992
Electric distribution	5,624	—	—	205	—	5,829
Steam and other production miscellaneous	1,521	—	—	57	—	1,578
Electric transmission	193	—	—	7	—	200
Steam production radiation sources	71	—	—	4	—	75
Natural gas plant						
Gas transmission and distribution	35,771	—	—	1,464	6,331	43,566
Gas storage asbestos	186	—	—	6	—	192
Common and other property						
Common general plant asbestos	579	—	(608)	29	—	—
Common miscellaneous	724	—	—	27	—	751
Total liability	\$ 2,452,567	\$ —	\$ (5,562)	\$ 121,987	\$ (485,119)	\$ 2,083,873

(a) The liabilities settled relate to asbestos abatement projects and the closure of certain ash containment facilities.

(b) In 2017, AROs were revised for changes in estimated cash flows and the timing of those cash flows. The nuclear decommissioning ARO decreased due to updated assumptions in the nuclear triennial filing.

(c) No liabilities were recognized during 2017.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$2.1 billion as of Dec. 31, 2017, consisting of external investment funds.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2016	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions ^(b)	Ending Balance Dec. 31, 2016
Electric plant						
Nuclear production decommissioning	\$ 2,141,024	\$ —	\$ —	\$ 108,298	\$ —	\$ 2,249,322
Wind production	69,654	17,305 ^(a)	—	3,147	—	90,106
Steam production ash containment	58,688	—	(6,271)	1,737	(12,415)	41,739
Steam, hydro and other production asbestos	25,692	—	—	1,039	—	26,731
Electric distribution	5,427	—	—	197	—	5,624
Steam, hydro and other production miscellaneous	1,663	431	—	63	(636)	1,521
Electric transmission	186	—	—	7	—	193
Steam production radiation sources	67	—	—	4	—	71
Natural gas plant						
Gas transmission and distribution	27,397	—	—	1,103	7,271	35,771
Gas storage asbestos	—	185	—	1	—	186
Common and other property						
Common general plant asbestos	551	—	—	28	—	579
Common miscellaneous	743	—	—	27	(46)	724
Total liability	\$ 2,331,092	\$ 17,921	\$ (6,271)	\$ 115,651	\$ (5,826)	\$ 2,452,567

(a) The liability recognized relates to the Courtenay Wind Farm which was placed in service during 2016.

(b) In 2016, AROs were revised for changes in estimated cash flows and the timing of those cash flows.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.9 billion as of Dec. 31, 2016, consisting of external investment funds.

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

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$13.4 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 \$13.0 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear incident. NSP-Minnesota is subject to assessments of up to \$127 million per reactor-incident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$19 million per reactor per incident during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective September 2013.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL) and European Mutual Association for Nuclear Insurance (EMANI). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain 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. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$19 million for business interruption insurance and \$41 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

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

Other Contingencies

See Note 8 for further discussion.

10. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or 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 has funded its portion of the DOE's permanent disposal program since 1981. Through May 2014, the fuel disposal fees were based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Since that time, the DOE has set the fee to zero. There were no DOE fuel disposal assessments in 2017 or 2016.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity is determined by the NRC and the MPUC. The Monticello dry-cask storage facility currently stores 16 of the 30 authorized canisters, and the PI dry-cask storage facility currently stores 40 of the 64 authorized casks.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Regulatory Plant Decommissioning Recovery — Decommissioning activities related to 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. The MPUC most recently approved NSP-Minnesota’s 2014 nuclear decommissioning study in October 2015. This cost study quantified decommissioning costs in 2014 dollars and utilized escalation rates of 4.36 percent per year for plant removal activities, and 3.36 percent for spent fuel management and site restoration activities over a 60-year decommissioning scenario.

The total obligation for decommissioning is expected to be funded 100 percent by the external decommissioning trust fund when decommissioning commences. NSP-Minnesota’s most recently approved decommissioning study resulted in an annual funding requirement of \$14 million to be recovered in utility customer rates which started in 2016. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23 percent and 6.30 percent. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota’s regulatory asset for nuclear decommissioning costs.

As of Dec. 31, 2017, NSP-Minnesota has accumulated \$2.1 billion of assets held in external decommissioning trusts. The following table summarizes the funded status of NSP-Minnesota’s decommissioning obligation based on parameters established in the most recently approved decommissioning study. Xcel Energy believes future decommissioning costs, if necessary, will continue to be recovered in customer rates. The amounts presented below were prepared on a regulatory basis, and are not recorded in the financial statements for the ARO.

(Thousands of Dollars)	Regulatory Basis	
	2017	2016
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	\$ 3,012,342	\$ 3,012,342
Effect of escalating costs (to 2017 and 2016 dollars, respectively, at 4.36/3.36 percent)	395,670	258,278
Estimated decommissioning cost obligation (in current dollars)	3,408,012	3,270,620
Effect of escalating costs to payment date (4.36/3.36 percent)	7,797,482	7,934,874
Estimated future decommissioning costs (undiscounted)	11,205,494	11,205,494
Effect of discounting obligation (using average risk-free interest rate of 2.80 percent and 3.25 percent for 2017 and 2016, respectively)	(6,398,052)	(7,068,362)
Discounted decommissioning cost obligation	\$ 4,807,442	\$ 4,137,132
Assets held in external decommissioning trust	\$ 2,143,281	\$ 1,860,762
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,664,161	2,276,370

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. The 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. The following table provides a reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Thousands of Dollars)	2017	2016
Discounted decommissioning cost obligation - regulated basis	\$ 4,807,442	\$ 4,137,132
Differences in discount rate and market risk premium	(1,402,846)	(1,043,655)
Operating costs not included for GAAP	(1,041,489)	(844,155)
ARO differences between 2017 and 2014 cost studies	(489,474)	—
Nuclear production decommissioning ARO - GAAP	\$ 1,873,633	\$ 2,249,322

Decommissioning expenses recognized as a result of regulation for the years ending Dec. 31 were:

(Thousands of Dollars)	2017	2016
Annual decommissioning recorded as depreciation expense: (a) (b)	\$ 20,372	\$ 20,372

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

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

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation for both 2017 and 2016. The most recent triennial filing was submitted in December 2017 and is currently pending with the MPUC, with an order expected in 2018.

11. Regulatory Assets and Liabilities

NSP-Minnesota's financial statements are prepared in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Regulatory Assets		
Asset retirement recovery	\$ 2,156,150	\$ 2,016,555
Pension and retiree medical obligations ^(a)	432,257	433,227
Theoretical depreciation reserve surplus	278,507	287,913
Excess deferred taxes - TCJA	133,061	—
Recoverable deferred taxes on AFUDC recorded in plant	118,964	206,729
Contract valuation adjustments ^(b)	104,179	117,480
Nuclear refueling outage costs	68,985	64,946
Renewable resources and environmental initiatives	47,590	49,805
Purchased power contracts costs	41,077	41,804
Conservation programs ^(c)	31,633	21,203
Environmental remediation costs	24,589	14,594
Sherco Unit 3 Deferral	8,717	9,157
Other	116,741	34,448
Other regulatory assets	<u>\$ 3,562,450</u>	<u>\$ 3,297,861</u>

(a) Includes \$178.5 million and \$241.0 million for the regulatory recognition of pension expense at Dec. 31, 2017 and 2016, respectively. Also included are \$0.9 million and \$1.0 million of regulatory assets related to the non-qualified pension plan at both Dec. 31, 2017 and 2016.

(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.

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

(Thousands of Dollars)	Dec. 31, 2017	Dec. 31, 2016
Regulatory Liabilities		
Plant removal costs	\$ 1,564,395	\$ 1,502,602
Deferred income tax adjustment	1,460,200	29,253
investments	398,650	239,373
Excess deferred taxes - TCJA ^(a)	55,904	—
Investment tax credit deferrals	15,420	25,577
DOE Settlement	11,205	13,833
Contract valuation adjustments ^(b)	17,157	15,321
Deferred electric energy costs	11,704	18,872
Other	44,122	23,626
Other regulatory liabilities ^(c)	<u>\$ 3,578,757</u>	<u>\$ 1,868,457</u>

(a) Primarily relates to the revaluation of recoverable/regulated plant ADIT and \$55.9 million revaluation impact of non-plant ADIT at Dec. 31, 2017.

(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) Revenue subject for refund of \$15.0 million and \$43.5 million for 2017 and 2016, respectively, is included in other current liabilities.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

At Dec. 31, 2017 and 2016, approximately \$142 million and \$73 million of NSP-Minnesota's regulatory assets represented past expenditures not currently earning a return, respectively. This amount primarily includes certain pension and recoverable purchased natural gas and electric energy costs.

12. Other Comprehensive Income

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

(Thousands of Dollars)	Year Ended Dec. 31, 2017			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (18,208)	\$ 105	\$ (2,680)	\$ (20,783)
Other comprehensive income (loss) before reclassifications	85	—	(566)	(481)
Losses reclassified from net accumulated other comprehensive loss	931	—	145	1,076
Net current period other comprehensive income (loss)	1,016	—	(421)	595
Adoption of ASU No. 2018-02 (a)	(3,703)	23	(669)	(4,349)
Accumulated other comprehensive (loss) income at Dec. 31	\$ (20,895)	\$ 128	\$ (3,770)	\$ (24,537)

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

(Thousands of Dollars)	Year Ended Dec. 31, 2016			
	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	\$ (19,090)	\$ 105	\$ (2,096)	\$ (21,081)
Other comprehensive loss before reclassifications	5	—	(661)	(656)
Losses (gains) reclassified from net accumulated other comprehensive loss	877	—	77	954
Net current period other comprehensive income (loss)	882	—	(584)	298
Accumulated other comprehensive (loss) income at Dec. 31	\$ (18,208)	\$ 105	\$ (2,680)	\$ (20,783)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss	
	Year Ended Dec. 31, 2017	Year Ended Dec. 31, 2016
Losses (gains) on cash flow hedges:		
Interest rate derivatives	\$ 1,571 (a)	\$ 1,392 (a)
Vehicle fuel derivatives	(38) (b)	104 (b)
Total, pre-tax	1,533	1,496
Tax benefit	(602)	(619)
Total, net of tax	931	877
Defined benefit pension and postretirement losses (gains):		
Amortization of net loss	436 (c)	332 (c)
Prior service cost	(198) (c)	(196) (c)
Total, pre-tax	238	136
Tax benefit	(93)	(59)
Total, net of tax	145	77
Total amounts reclassified, net of tax	\$ 1,076	\$ 954

(a) Included in interest charges.

(b) Included in operating expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 6 for details regarding these benefit plans.

13. Related Party Transactions

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

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 3 for further discussion.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

(Thousands of Dollars)	2017	2016
Operating revenues:		
Electric	\$ 490,221	\$ 475,534
Gas	47	41
Operating expenses:		
Purchased power	66,776	63,018
Transmission expense	110,457	107,466
Other operating expenses — paid to Xcel Energy Services Inc.	539,425	512,967
Interest expense	—	49
Interest income	—	—

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

(Thousands of Dollars)	2017		2016	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 17,825	\$ —	\$ 18,567	\$ —
PSCo	—	7,738	—	7,669
SPS	—	964	—	935
Other subsidiaries of Xcel Energy Inc.	30,669	73,577	32,824	51,029
	\$ 48,494	\$ 82,279	\$ 51,390	\$ 59,633

14. Supplementary Cash Flow Data

(Thousands of Dollars)	2017	2016
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	\$ (219,934)	\$ (203,191)
Cash paid for income taxes, net	(71,032)	(39,013)
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	\$ 74,166	\$ 103,459

15. Energy Storage Assets (FERC Order No. 784)

The FERC issued Order No. 784, "Third-Party Provision of Ancillary Services; Accounting and Financial Reporting For New Electric Storage Technologies" in July 2013. In February 2014, FERC issued guidance on complying with Order No. 784's new accounting and disclosure requirements until their Form 1 and Form 3 statements are revised to accommodate the changes. That guidance included a requirement to include disclosure information related to energy storage technologies in the notes to the financial statements. This information is presented below.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The Luverne Wind2Battery project is a one MW sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind wind power generating facility near Luverne, Minn. It is being used to store, control and dispatch energy when needed for supply or transmission stability purposes. The purpose of the facility is to provide NSP-Minnesota with experience and information that will allow NSP-Minnesota to assess and improve upon the viability of scaling up battery storage on the system as more wind power is added to meet the renewable policies.

Energy Plant Account

Energy storage assets are recorded in Account 348 in the amount of \$4,128,902 at Dec. 31, 2017 and 2016. Due to FERC software limitations, these amounts are reported in Account 342.

Power Purchased Account

Energy storage-related purchased power costs are recorded in Account 555.1 in accordance with FERC Order No. 784 in the credit amount of \$23,977 and in the amount of \$3,209 for the year ended Dec. 31 2017 and 2016, respectively, reflecting true-up activity during the period. Due to FERC software limitations, these amounts are reported in Account 555.

Operation and Maintenance Expense Accounts

Energy storage-related operating expenses are recorded in Account 548.1 in accordance with FERC Order No. 784 in the amount of zero and \$9,024 for the year ended Dec. 31, 2017 and 2016, respectively. Due to FERC software limitations, these amounts are reported in Account 548.

Energy storage-related maintenance expenses are recorded in Account 553.1 in accordance with FERC Order No. 784 in the amount of zero and \$78,057 for the year ended Dec. 31, 2017 and 2016, respectively. Due to FERC software limitations, these amounts are reported in Account 553.

The following tables present NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2017, as required by FERC Order No. 784:

Line no.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	\$ 4,128,902	\$ —	\$ —	\$ —	\$ (23,977)	\$ —

The following tables present NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2016, as required by FERC Order No. 784:

Line no.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	\$ 4,128,902	\$ 9,024	\$ 78,057	\$ —	\$ 3,209	\$ —

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	849,024			(2,840,861)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				77,089
3	Preceding Quarter/Year to Date Changes in Fair Value	882			(660,998)
4	Total (lines 2 and 3)	882			(583,909)
5	Balance of Account 219 at End of Preceding Quarter/Year	849,906			(3,424,770)
6	Balance of Account 219 at Beginning of Current Year	849,906			(3,424,770)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	23,136			(524,084)
8	Current Quarter/Year to Date Changes in Fair Value	385			(565,692)
9	Total (lines 7 and 8)	23,521			(1,089,776)
10	Balance of Account 219 at End of Current Quarter/Year	873,427			(4,514,546)

Name of Respondent
Northern States Power Company (Minnesota)

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/06/2018

Year/Period of Report
End of 2017/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 [Insert Footnote at Line 1to 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	(19,000,031)	(89,470)	(21,081,338)		
2	815,200	61,952	954,241		
3		4,504	(655,612)		
4	815,200	66,456	298,629	488,743,682	489,042,311
5	(18,184,831)	(23,014)	(20,782,709)		
6	(18,184,831)	(23,014)	(20,782,709)		
7	(2,763,287)	(22,527)	(3,286,762)		
8		98,292	(467,015)		
9	(2,763,287)	75,765	(3,753,777)	490,121,306	486,367,529
10	(20,948,118)	52,751	(24,536,486)		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 122(a)(b) Line No.: 1 Column: g

Other cash flow hedging activity relates primarily to vehicle fuel and natural gas commodity derivatives.

This footnote applies to all of column g.

Schedule Page: 122(a)(b) Line No.: 7 Column: b

The amount reported relates to the reclassification of Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Includes a (\$668,931) reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Schedule Page: 122(a)(b) Line No.: 7 Column: f

Includes a (\$3,716,417) reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Schedule Page: 122(a)(b) Line No.: 7 Column: g

Includes a \$13,432 reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

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)	17,037,616,725	15,196,577,652
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	2,241,855,208	2,001,901,567
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	19,279,471,933	17,198,479,219
9	Leased to Others		
10	Held for Future Use	19,360,375	19,360,375
11	Construction Work in Progress	529,931,771	442,824,158
12	Acquisition Adjustments	222,385	222,385
13	Total Utility Plant (8 thru 12)	19,828,986,464	17,660,886,137
14	Accum Prov for Depr, Amort, & Depl	7,766,026,424	6,903,014,351
15	Net Utility Plant (13 less 14)	12,062,960,040	10,757,871,786
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,453,029,116	6,752,582,070
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	312,774,923	150,209,896
22	Total In Service (18 thru 21)	7,765,804,039	6,902,791,966
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	222,385	222,385
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,766,026,424	6,903,014,351

Name of Respondent
Northern States Power Company (Minnesota)

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/06/2018

Year/Period of Report
End of 2017/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
1,304,751,817				536,287,256	3
					4
					5
65,578,630				174,375,011	6
					7
1,370,330,447				710,662,267	8
					9
					10
29,851,274				57,256,339	11
					12
1,400,181,721				767,918,606	13
605,099,729				257,912,344	14
795,081,992				510,006,262	15
					16
					17
600,404,755				100,042,291	18
					19
					20
4,694,974				157,870,053	21
605,099,729				257,912,344	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
605,099,729				257,912,344	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 200 Line No.: 21 Column: c

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	\$ 81,403,644
Nuclear Production Plant	65,266,492
Hydraulic Production Plant-Conventional	2,365,051
Other Production Plant	1,174,709
Total Amort of Other Utility Plant - Electric	<u>\$150,209,896</u>

Schedule Page: 200 Line No.: 32 Column: c

The amortization of plant acquisition adjustment within account 115 includes the following:

Transmission	\$ 222,385
--------------	------------

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	19,412,147	20,169,207
3	Nuclear Materials	171,292,191	91,451,707
4	Allowance for Funds Used during Construction	14,640,376	11,929,860
5	(Other Overhead Construction Costs, provide details in footnote)	180,735	-26,385
6	SUBTOTAL (Total 2 thru 5)	205,525,449	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		2,377,108
9	In Reactor (120.3)	526,657,578	148,754,396
10	SUBTOTAL (Total 8 & 9)	526,657,578	
11	Spent Nuclear Fuel (120.4)	1,839,587,125	140,072,301
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,180,635,866	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	391,134,286	
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)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
	33,554,276	6,027,078	2
	103,223,334	159,520,564	3
	9,760,147	16,810,089	4
	99,258	55,092	5
		182,412,823	6
			7
	2,377,108		8
	140,072,301	535,339,673	9
		535,339,673	10
		1,979,659,426	11
			12
-114,361,824		2,294,997,690	13
		402,414,232	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 202 Line No.: 2 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 3 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 4 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 5 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 5 Column: f

Consists of Administration and General costs

Schedule Page: 202 Line No.: 8 Column: c

Consists of transfers from 120.1, and direct trailing charges to asset after in-service

Schedule Page: 202 Line No.: 8 Column: e

Transferred to Account 120.3

Schedule Page: 202 Line No.: 9 Column: e

Transferred to Account 120.4

Schedule Page: 202 Line No.: 15 Column: f

Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

Schedule Page: 202 Line No.: 16 Column: f

Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

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	236,425,844	649,542
4	(303) Miscellaneous Intangible Plant	115,172,554	4,697,127
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	351,598,398	5,346,669
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,497,630	64,855
9	(311) Structures and Improvements	288,346,053	541,183
10	(312) Boiler Plant Equipment	1,422,960,308	30,783,283
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	305,754,436	4,448,610
13	(315) Accessory Electric Equipment	183,570,951	2,232,630
14	(316) Misc. Power Plant Equipment	53,996,868	67,535
15	(317) Asset Retirement Costs for Steam Production	-3,899,915	-6,930,631
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,259,226,331	31,207,465
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,762,309	53
19	(321) Structures and Improvements	531,378,298	30,591,071
20	(322) Reactor Plant Equipment	1,572,664,588	49,560,656
21	(323) Turbogenerator Units	590,449,763	5,473,284
22	(324) Accessory Electric Equipment	460,486,529	30,088,613
23	(325) Misc. Power Plant Equipment	205,423,488	1,575,614
24	(326) Asset Retirement Costs for Nuclear Production	482,670,802	-489,474,122
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,844,835,777	-372,184,831
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,693,076	
28	(331) Structures and Improvements	1,387,646	
29	(332) Reservoirs, Dams, and Waterways	10,806,684	24,440
30	(333) Water Wheels, Turbines, and Generators	10,038,998	18,494
31	(334) Accessory Electric Equipment	3,256,971	
32	(335) Misc. Power PLant Equipment	60,825	
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)	27,244,200	42,934
36	D. Other Production Plant		
37	(340) Land and Land Rights	21,957,822	-4,365
38	(341) Structures and Improvements	259,033,584	2,817,830
39	(342) Fuel Holders, Products, and Accessories	88,747,763	-107,436
40	(343) Prime Movers		
41	(344) Generators	2,182,714,249	7,469,969
42	(345) Accessory Electric Equipment	269,079,709	3,529,178
43	(346) Misc. Power Plant Equipment	31,276,051	166,229
44	(347) Asset Retirement Costs for Other Production	77,834,222	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,930,643,400	13,871,405
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	9,061,949,708	-327,063,027

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	152,708,017	9,465,708
49	(352) Structures and Improvements	103,086,367	4,205,385
50	(353) Station Equipment	1,181,449,211	39,251,766
51	(354) Towers and Fixtures	118,631,859	38,199
52	(355) Poles and Fixtures	1,330,556,062	64,044,761
53	(356) Overhead Conductors and Devices	532,704,102	19,768,423
54	(357) Underground Conduit	25,910,138	3,074,051
55	(358) Underground Conductors and Devices	30,710,573	6,516,004
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,475,929,758	146,364,297
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	16,463,375	923,272
61	(361) Structures and Improvements	49,190,222	2,089,252
62	(362) Station Equipment	625,704,200	20,582,769
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	392,283,081	22,591,709
65	(365) Overhead Conductors and Devices	436,929,363	36,311,122
66	(366) Underground Conduit	285,899,131	15,576,337
67	(367) Underground Conductors and Devices	1,114,687,520	28,730,480
68	(368) Line Transformers	442,914,723	19,563,919
69	(369) Services	296,242,543	12,813,077
70	(370) Meters	111,266,652	6,442,107
71	(371) Installations on Customer Premises	22,705,174	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	70,068,994	7,236,826
74	(374) Asset Retirement Costs for Distribution Plant	3,770,269	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,868,125,247	172,860,870
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	4,438,920	45,181
87	(390) Structures and Improvements	63,543,958	2,810,087
88	(391) Office Furniture and Equipment	59,991,917	6,880,730
89	(392) Transportation Equipment	149,408,723	18,874,028
90	(393) Stores Equipment	1,648,791	9,615
91	(394) Tools, Shop and Garage Equipment	81,301,140	8,867,825
92	(395) Laboratory Equipment	3,209,733	215,972
93	(396) Power Operated Equipment	45,134,820	2,150,060
94	(397) Communication Equipment	77,997,408	25,165,516
95	(398) Miscellaneous Equipment	2,723,841	695,422
96	SUBTOTAL (Enter Total of lines 86 thru 95)	489,399,251	65,714,436
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	489,399,251	65,714,436
100	TOTAL (Accounts 101 and 106)	17,247,002,362	63,223,245
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)	17,247,002,362	63,223,245

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
			237,075,386		3
7,590,460			112,279,221		4
7,590,460			349,354,607		5
					6
					7
88			8,562,397		8
173,423		96,034	288,809,847		9
10,477,695			1,443,265,896		10
					11
2,891,641		-462,541	306,848,864		12
338,279		127	185,465,429		13
19,499			54,044,904		14
-16,316,468			5,485,922		15
-2,415,843		-366,380	2,292,483,259		16
					17
			1,762,362		18
3,280,743			558,688,626		19
8,794,065		106,272,224	1,719,703,403		20
3,609,645		-106,272,224	486,041,178		21
1,413,541			489,161,601		22
298,817			206,700,285		23
			-6,803,320		24
17,396,811			3,455,254,135		25
					26
			1,693,076		27
			1,387,646		28
1,259			10,829,865		29
			10,057,492		30
			3,256,971		31
			60,825		32
					33
					34
1,259			27,285,875		35
					36
15,949			21,937,508		37
195,757			261,655,657		38
23,977			88,616,350		39
					40
8,989,441		462,541	2,181,657,318		41
710,215		-127	271,898,545		42
175			31,442,105		43
			77,834,222		44
9,935,514		462,414	2,935,041,705		45
24,917,741		96,034	8,710,064,974		46

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
			162,173,725	48
293,468			106,998,284	49
5,564,753			1,215,136,224	50
234,767			118,435,291	51
12,670,748		30,352	1,381,960,427	52
11,125,861		-30,352	541,316,312	53
7,882			28,976,307	54
			37,226,577	55
				56
			173,429	57
29,897,479			3,592,396,576	58
				59
16,045			17,370,602	60
44,007			51,235,467	61
2,170,651			644,116,318	62
				63
701,685			414,173,105	64
2,719,142			470,521,343	65
415,636			301,059,832	66
2,540,803			1,140,877,197	67
13,181,912			449,296,730	68
1,362,091			307,693,529	69
8,543,574			109,165,185	70
			22,705,174	71
				72
8,132,676			69,173,144	73
			3,770,269	74
39,828,222			4,001,157,895	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			4,484,101	86
1,071,008		-96,034	65,187,003	87
1,038,605			65,834,042	88
4,609,134			163,673,617	89
26,668			1,631,738	90
267,599			89,901,366	91
428,134			2,997,571	92
1,180,759			46,104,121	93
807,999			102,354,925	94
82,580			3,336,683	95
9,512,486		-96,034	545,505,167	96
				97
				98
9,512,486		-96,034	545,505,167	99
111,746,388			17,198,479,219	100
				101
				102
				103
111,746,388			17,198,479,219	104

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 204 Line No.: 5 Column: g

This footnote also applies to the following pages, lines and columns:

Schedule Page: 205 Line No: 46 Column: g
Schedule Page: 207 Line No: 58 Column: g
Schedule Page: 207 Line No: 75 Column: g
Schedule Page: 207 Line No: 99 Column: g

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

Schedule Page: 204 Line No.: 39 Column: g

Account 342 Fuel Holders, Producers, and Accessories	\$84,487,448
Account 348 Energy Storage, Equipment - Production	4,128,902
	\$88,616,350

Schedule Page: 204 Line No.: 58 Column: g

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	157,969	(120,845)	-	-	-	37,124
Account 352 - Structures & Improvements	14,204,626	(55,328)	(201)	-	-	14,149,097
Account 353 - Station Equipment	58,697,164	(63,811)	(61,615)	-	-	58,571,738
Account 354 - Towers & Fixtures	5,261,904	41,559	-	-	-	5,303,463
Account 355 - Poles & Fixtures	13,275,634	(795,808)	-	-	-	12,479,826
Account 356 - Overhead Conductors & Devices	847,968	-	(139)	-	-	847,829

Schedule Page: 204 Line No.: 75 Column: g

Distribution Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 361 - Structures & Improvements	838,281	-	-	-	-	838,281
Account 362 - Station Equipment	2,692,338	-	-	-	-	2,692,338

Name of Respondent
Northern States Power Company (Minnesota)

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/06/2018

Year/Period of Report
End of 2017/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					
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					
42					
43					
44					
45					
46					
47	TOTAL				

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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Nuclear Dry Fuel Canisters, Monticello Nuc Gen Plant	2014	2018	5,799,435
23	Nuclear Dry Fuel Canisters, Prairie Is Nuc Gen Plant	2017	2020	13,560,940
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46	Footnote from page 106b			
47	Total			19,360,375

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 46 Column: d

Electric Plant Held for Future Use (Account 105). The Form 1 reports the plant held for future use balances at the end of the year. NSP-Minnesota uses only the transmission-related land and land rights plant held for future use in the formula. NSP-Minnesota uses a 13-month average calculation of these plant balances included in the formula rate.

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	BDS0C Black Dog U6 Simple Cycl	78,630,831
2	PI-9 TN-40 Casks(39-47)	29,685,947
3	PI-NFPA 805 Fire Model	20,700,708
4	MNGP 2018 Dry Fuel Storage Loa	16,314,178
5	MNGP DAS & PPCS Rplc	15,045,897
6	PI U1 Generator Replacemnt LCM	14,798,586
7	ADMS SW MN	13,862,644
8	New 230kV Line 0924	10,283,981
9	PI Proc Controls Repl	7,184,833
10	PI U2 HDTP Speed Control Upgr	6,604,786
11	Purch ADMS EL Net Server GO MN	6,206,358
12	MNGP Security Mods Post Reduct	6,018,585
13	PI NFPA 805-24 CT11CT12 Brkrs	5,846,199
14	SHC1C U1 Turbine Replacement	5,098,983
15	PI Sfgds CL Pump Redesign	4,856,288
16	PI 124 CT Deck, Header, Valves	4,444,229
17	GIST-IV Computer Software NSPM	4,351,994
18	PI 124 CT Structural & Fan Drives	4,123,753
19	PI 4.16 KV Bus Modifications	4,109,641
20	Pomerleau Lake Sub	4,076,537
21	Install Fifth Street Switchgea	3,944,338
22	Northwest Solar Gardens Ext	3,833,763
23	PI 1R Transformer Replacement	3,796,717
24	PI NFPA 805-03 U1 Train B AFW	3,796,545
25	BDS5C U5 CT HGP	3,720,265
26	FOX G100-Foxtail Wind Farm	3,691,286
27	MNGP Byron Station Electric Vo	3,604,683
28	Solar Garden Ext - WBL	3,518,616
29	MN - UG Extension Blanket	3,178,951
30	G100-Crowned Ridge BOT Wind Farm	2,526,097
31	Magic City Sub	2,515,216
32	ASK1C 12 BFPT Steam Path Replace	2,427,002
33	PI EEQ Computer Model	2,301,759
34	MN Transportation Units Over 50K	2,215,939
35	PI Namco Limit Switch Repl	2,180,546
36	ASK1C 13 BFPT Steam Path Replace	2,106,209
37	Install WCS TR2 and 2 fdr bays	2,078,640
38	PI NFPA 805-14 RL Sw AFW Rm	2,065,057
39	Frame Relay Replacement - NSPM	1,997,935
40	BDS2C U2 Boiler Feed Pumps Replc	1,943,122
41	Gleason Lake Cap Bank Sub	1,928,078
42	Huntley Wilmarth Precertification	1,887,240
43	TOTAL	442,824,158

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	DKR0 Dakota Range Wind Turbines	1,868,847
2	NSPM Physical Security Sub Infrastr	1,868,696
3	MNGP EDG Rplc & Voltage Reg	1,807,219
4	PI NFPA 805-10 Loss OCT 4KV Br	1,771,303
5	MN - Feeder Cable Replacement Blank	1,707,954
6	PI 12 Reactor Coolant Pump Refurb	1,669,177
7	PI ISFSI Expansion	1,659,398
8	Purch CIP Appl MN	1,650,361
9	SHC1C L_0 Bucket Replacement	1,554,748
10	PI NFPA 805-01 U1 Train A AFW	1,513,915
11	Diagnostic Center Ph 4 SW MN only	1,464,132
12	G100-Freeborn Wind Farm	1,453,964
13	0814 Rebuild Line	1,426,756
14	ANS3C U3 Major Overhaul	1,404,712
15	G100-Blazing Star I Wind Farm	1,391,569
16	MN-Dist Fleet New Unit Purchase EI	1,308,028
17	5571 MPR RED 2nd 115kV Circuit Line	1,290,550
18	Fenton ReactorSub	1,273,008
19	MN-Dist Electric Tools and Equip	1,225,349
20	Add third transformer at Nordi	1,208,311
21	PI NUS Proc Controls Foxboro Mod Re	1,154,155
22	NSPM Transmission UAV	1,149,645
23	MN - URD Cable Replacement Blanket	1,142,896
24	MN Frame Relay Comm	1,110,745
25	0894 Rebuild Line	1,090,398
26	SD - UG Extension Blanket	1,076,890
27	Reinforce Lowry TR1, replace regula	1,063,635
28	HBC9C ST L-O Blade Replacement	1,033,058
29	PI NFPA 805-25 Repowr MV-32078	1,024,968
30	MT KM 480VAC Cubicle Rplc	1,002,701
31		
32	Minor Projects	77,954,108
33		
34		
35		
36		
37		
38		
39		
40		
41	Footnote from Page 106b	
42		
43	TOTAL	442,824,158

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 216.1 Line No.: 41 Column: b

Construction Work in Progress (Account 107). The Form 1 reports the total Company construction work in progress (CWIP) balances at the end of the year. The Company uses a 13-month average calculation for the specific CWIP project balances included in the formula. The Company can only include CWIP in the formula related to the following specific projects, the balances of which could be a component of the amounts reported on page 216: the three projects in Group 1 of the CapX2020 Project - Twin Cities-Brookings County, Twin Cities-Fargo, and Twin Cities-LaCrosse.

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	6,367,401,231	6,367,401,231		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	507,343,373	507,343,373		
4	(403.1) Depreciation Expense for Asset Retirement Costs	18,220,589	18,220,589		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	14,997,474	14,997,474		
7	Other Clearing Accounts	161,246	161,246		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	540,722,682	540,722,682		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	120,472,397	120,472,397		
13	Cost of Removal	44,081,179	44,081,179		
14	Salvage (Credit)	10,458,998	10,458,998		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	154,094,578	154,094,578		
16	Other Debit or Cr. Items (Describe, details in footnote):	-17,763,733	-17,763,733		
17					
18	Book Cost or Asset Retirement Costs Retired	16,316,468	16,316,468		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,752,582,070	6,752,582,070		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	1,421,686,052	1,421,686,052		
21	Nuclear Production	1,829,751,560	1,829,751,560		
22	Hydraulic Production-Conventional	10,982,226	10,982,226		
23	Hydraulic Production-Pumped Storage				
24	Other Production	820,006,559	820,006,559		
25	Transmission	854,348,586	854,348,586		
26	Distribution	1,585,108,386	1,585,108,386		
27	Regional Transmission and Market Operation				
28	General	230,698,701	230,698,701		
29	TOTAL (Enter Total of lines 20 thru 28)	6,752,582,070	6,752,582,070		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 16 Column: c

Net change in RWIP	\$ (15,429,522)
Net Transfers	(1,211,773)
Gain/Loss	(1,122,438)
Total	<u>\$ (17,763,733)</u>

Schedule Page: 219 Line No.: 20 Column: c

Schedule Page: 219
Line No: 20-26, 28
Column: c

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

Schedule Page: 219 Line No.: 25 Column: c

Transmission Serving Production	\$ 37,177,106
---------------------------------	---------------

Schedule Page: 219 Line No.: 26 Column: c

Distribution Serving Production	\$ 2,125,833
---------------------------------	--------------

Schedule Page: 219 Line No.: 29 Column: b

	"Non-Legal" ARO Balances
Steam Production	<u>\$ 85,081,796</u>
Nuclear Production	(91,158,112)
Hydraulic Production-Conventional	1,901,892
Other Production	34,575,323
Transmission	105,937,622
Distribution	217,785,081
General	(705,916)
Total	<u>\$ 353,417,686</u>

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	UNITED POWER & LAND CO.			
2	Common Stock-par \$100 per share			4,020,000
3	Additional Paid in Capital			399,765
4	Undistributed earnings (loss) since acquisition			-3,362,846
5	SUBTOTAL			1,056,919
6				
7	NSP NUCLEAR CO.			
8	Contributed Capital			963,198
9	Undistributed earnings (loss) since acquisition			552,990
10	SUBTOTAL			1,516,188
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				
41				
42	Total Cost of Account 123.1 \$		TOTAL	5,382,922 2,573,107

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 from investments, including such revenues from 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
		4,020,000		2
	-41	399,724		3
-123,813		-3,486,659		4
-123,813	-41	933,065		5
				6
				7
		963,198		8
-3,077		549,913		9
-3,077		1,513,111		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
				41
-126,890	-41	2,446,176		42

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 224 Line No.: 3 Column: f
Annual allocation of unitary tax (benefit)/detriment.

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)	100,686,129	97,129,106	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)	24,596,470	47,056,876	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	188,937,211	164,146,973	Electric
8	Transmission Plant (Estimated)	532,649	1,145,534	Electric
9	Distribution Plant (Estimated)	3,481,198	2,675,885	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-4,260,077	-6,570,632	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	213,287,451	208,454,636	
13	Merchandise (Account 155)	942,563	752,710	
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	note re: page 106 formula rates			
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	314,916,143	306,336,452	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 11 Column: b

Includes a credit of \$3,051,287 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$1,208,790 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 11 Column: c

Includes a credit of \$2,859,505 for inventory allocated to Southern Minnesota municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$3,711,127 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 18 Column: a

Materials & Supplies (Accounts 154 and 163). The Form 1 reports the materials and supplies balances at the beginning and end of the year. The Company uses the average of the beginning and end of the year materials and supplies balances in the formula rate (see page 106).

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		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	760,295.00		95,592.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	86,353.00		86,353.00	
5	Returned by EPA	527.00			
6					
7					
8	Purchases/Transfers:				
9	Transfer to SMMPA	-4,971.00			
10					
11					
12					
13					
14					
15	Total	-4,971.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	11,768.00			
19	Other:				
20	Adjust Balance	99,772.00		95,592.00	
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	730,664.00		86,353.00	
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	925.00		925.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	925.00			
40	Balance-End of Year			925.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	925.00	76		
45	Gains		76		
46	Losses				

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/transfersors 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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
95,592.00		95,592.00		1,774,482.00		2,821,553.00		1
								2
								3
86,353.00		86,353.00		1,554,354.00		1,899,766.00		4
						527.00		5
								6
								7
								8
						-4,971.00		9
								10
								11
								12
								13
								14
						-4,971.00		15
								16
								17
						11,768.00		18
								19
95,592.00		95,592.00		1,774,482.00		2,161,030.00		20
								21
								22
								23
								24
								25
								26
								27
								28
86,353.00		86,353.00		1,554,354.00		2,544,077.00		29
								30
								31
								32
								33
								34
								35
925.00		925.00		44,397.00		48,097.00		36
				1,850.00		1,850.00		37
								38
				925.00		1,850.00		39
925.00		925.00		45,322.00		48,097.00		40
								41
								42
								43
						925.00		76 44
								76 45
								46

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 44 Column: m

Proceeds from SO2 allowance sales from plants owned by NSP-Minnesota. This amount will not agree to Account 411.8 on the Income Statement (see page 114-117) due to proceeds from the sale of Renewable Energy Credits, sharing of the sale proceeds through the FERC-approved Interchange Agreement, and the specific regulatory treatment prescribed by the Minnesota, North Dakota, and South Dakota state regulatory commissions.

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		2018	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	30,325.00		17,635.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	17,635.00		17,635.00	
5	Returned by EPA	362.00			
6					
7					
8	Purchases/Transfers:				
9	Transfer to SMMPA	-1,474.00			
10					
11					
12					
13					
14					
15	Total	-1,474.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	10,432.00			
19	Other:				
20	Adjust Balance	17,586.00		17,635.00	
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	18,830.00		17,635.00	
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				

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/transfersors 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.

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
17,635.00		17,635.00		37,865.00		121,095.00		1
								2
								3
17,635.00		17,635.00		317,430.00		387,970.00		4
						362.00		5
								6
								7
								8
						-1,474.00		9
								10
								11
								12
								13
								14
						-1,474.00		15
								16
								17
						10,432.00		18
								19
17,635.00		17,635.00		37,865.00		108,356.00		20
								21
								22
								23
								24
								25
								26
								27
								28
17,635.00		17,635.00		317,430.00		389,165.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	--	--

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Prairie Island	78,884,915		Various	3,348,564	61,711,558
22	Extended Power Uprate project					
23	MPUC Docket No.					
24	E002/CN-08-509					
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	78,884,915			3,348,564	61,711,558

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 21 Column: a

In 2009, the Minnesota Public Utilities Commission (MPUC) granted NSP-Minnesota a Certificate of Need for an Extended Power Uprate (EPU) project at the Prairie Island (PI) nuclear generating plant. The total estimated cost of the EPU was \$294 million, of which approximately \$78.9 million had been incurred through 2012, including AFUDC of approximately \$12.8 million. Subsequently, NSP-Minnesota made a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In February 2013, the MPUC issued an order terminating the CON for the PI EPU project.

In its 2014 Minnesota retail electric rate case under MPUC Docket 13-868, NSP-Minnesota received recovery of approximately \$59 million of deferred costs plus a debt-only return of 2.24 percent, to be recovered over 20.3 years.

On Nov. 19, 2015, the FERC approved a request under FERC Docket ER15-698 to allocate a portion of the amortization and debt-only return to NSP-Wisconsin under the Interchange Agreement. Approximately \$12 million will be amortized, beginning on Jan. 1, 2016 and continuing for 18.3 years.

NSP-Minnesota intends to seek recovery of North Dakota and South Dakota jurisdictional amounts in future rate proceedings.

Schedule Page: 230 Line No.: 21 Column: b

Transfers from Account No. 107 during 2012	\$ 77,690,096
Transfers from Account No. 107 during 2013	1,194,819
	\$ 78,884,915

Schedule Page: 230 Line No.: 21 Column: d

Account No. 232 - MISO transmission study refund	\$ 60,904
Account No. 426.5 - accretion during 2017	(494,225)
Account No. 407 - amortization during 2017	3,781,885
	\$ 3,348,564

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	J569 Facility Study (35003487)	23,209	561.7	23,209	561.7
23	J399 Facility Study (35152457)	33,680	561.7	30,278	561.7
24	R102 Facility Study (60010171586)	2,174	561.7	2,174	561.7
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 231 Line No.: 22 Column: a

The values reported on this page represent the actual costs incurred or reimbursements received in the reporting period. As a result, cost and reimbursements for each study may be reported in different reporting periods.

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Conservation and Energy Management Program Costs	19,401,641	157,765,620	Various	145,654,735	31,512,526
2	Minnesota Electric					
3	- MN Docket E-002/M-17-259					
4	- Generally amortized over 12 month					
5	period following the expenditure					
6						
7	Conservation and Energy Management Program Costs	1,664,005	21,330,813	Various	22,994,818	
8	Minnesota Natural Gas					
9	- MN Docket G-002/M-17-258					
10	- Generally amortized over 12 month					
11	period following the expenditure					
12						
13	Conservation and Energy Management Program Costs	137,737	1,047,030	908	1,064,148	120,619
14	South Dakota Electric					
15	- SD Docket EL-16-018					
16	- Generally amortized over 12 month					
17	period following the expenditure					
18						
19	Net of Tax AFUDC in Plant Adjustments	206,728,907	3,400,854	Various	91,165,554	118,964,207
20						
21	South Dakota Ratemaking Differences	3,622,250	234,000	419.1	363,000	3,493,250
22	- SD Docket F-3382					
23	- SD Docket F-3422					
24						
25	Renewable Development Fund Rider	46,307,551	30,249,001	407.3	30,761,143	45,795,409
26	- MN Docket E-002/M-16-811					
27						
28	Asset Retirement Recovery	2,016,554,677	139,595,352			2,156,150,029
29						
30	Minnesota Gas State Energy Policy Rider		1,675,172	Various	1,420,098	255,074
31	- MN Docket G-002/M-16-206					
32						
33	Minnesota Transmission Cost Recovery Rider	298,507	88,691,056	Various	88,204,826	784,737
34	- MN Docket E-002/M-07-1156					
35	- MN Docket E-002/M-15-891					
36						
37	Power Contract Valuation Adjustment	117,479,779		244	13,300,311	104,179,468
38						
39	Costs to Relocate Facilities Underground	312,352	695,777	142	289,770	718,359
40	- MN Docket E-002/M-15-826					
41						
42						
43						
44	TOTAL	3,297,860,533	1,583,926,132		1,319,336,923	3,562,449,742

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Private Fuel Storage	60,436		407.3	57,795	2,641
2	- Amortized over 6 years					
3	- SD Docket EL14-058 (Amortized 01/2010-01/2018)					
4						
5	Minnesota Deferred Electric Commodity Costs		769,647,758	Various	765,088,372	4,559,386
6	- MN Docket E-002/M-14-364					
7						
8	Mankato/Cannon Falls Lease Normalization	41,804,014	1,007,816	253	1,734,636	41,077,194
9						
10	Minnesota Renewable Energy Standard Rider	1,279,185	11,830,925	Various	13,110,110	
11	- MN Docket E-002/M-15-805					
12						
13	Deferred Nuclear Outage Costs	64,946,477	66,960,752	Various	62,922,146	68,985,083
14	- Generally amortized over 23-24 months					
15	- MN Docket E-002/M-07-1489					
16	- ND Docket PU-07-774					
17	- SD Docket EL-07-035					
18						
19	Benefit Cost Recovery Deficit	433,227,363	34,066,486	184	35,036,738	432,257,111
20						
21	South Dakota Transmission Cost Recovery Rider	1,061,266	6,596,843	407.3	7,658,109	
22	-SD Docket EL-16-031					
23						
24	Transmission Formula Rates	14,221,481	7,441,837	456.1	8,680,449	12,982,869
25						
26	Sherco 3 Depreciation Deferral	9,156,894		407.3	439,464	8,717,430
27	-MN Docket E-002/GR-15-826					
28	- Amortized over 21 years (01/2014-12/2035)					
29						
30	Theoretical Depreciation Reserve Surplus	287,913,115		407.3	9,406,433	278,506,682
31	-MN Docket E-002/GR-15-826					
32						
33	North Dakota Transmission Cost Recovery Rider	858,526	6,323,412	407.3	7,109,618	72,320
34	- ND Docket PU-16-658					
35						
36	Gas Utility Infrastructure Cost Rider	16,150,037	21,526,491	Various	10,584,878	27,091,650
37	- MN Docket G-002/M-15-808					
38						
39	Minnesota Electric Vehicle Tariff	80,568	101,423			181,991
40	- MN Docket E-002/M-15-111					
41						
42	North Dakota Environmental Cleanup	14,593,765	5,126,767			19,720,532
43	- ND Docket PU-15-514					
44	TOTAL	3,297,860,533	1,583,926,132		1,319,336,923	3,562,449,742

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	South Dakota Property Tax Collected in the		1,347,618	142	936,659	410,959
2	Fuel Clause Adjustment					
3	- SD Docket EL 14-058					
4						
5	Minnesota Revenue Decoupling 2017		27,095,792			27,095,792
6	- MN Docket E-002/GR-13-868					
7	- MN Docket E-002/GR-15-826					
8	- Amortized over 1 year (04/2018-03/2019)					
9						
10	2016 Minnesota Deferred Property Tax		16,360,244			16,360,244
11	- MN docket E-002/GR-15-826					
12	- Amortized over 2 years (01/2018-12/2019)					
13						
14	2017 Minnesota Sales True-up		22,667,432			22,667,432
15	- MN Docket E-002/GR-15-826					
16	- Amortized over 1 year (04/2018-03/2019)					
17						
18	Benson Biomass PPA Termination		22,500			22,500
19	- MN Docket E-002/GR-17-530					
20	- ND Docket PU-17-271					
21						
22	Minnesota LED Streetlighting Deferral		686,612			686,612
23	- MN Docket E-002/GR-15-826					
24						
25	Nonplant Excess ADIT		133,060,653			133,060,653
26						
27	Renewable*Connect Classic		2,059,094	142	1,180,969	878,125
28	- MN Docket E-002/GR-15-985					
29						
30	Renewable*Connect Government		231,674	142	172,144	59,530
31	- MN Docket E-002/GR-15-985					
32						
33	South Dakota REC Sales		3,514			3,514
34	- SD Docket EL-09-009					
35						
36	Minnesota Environmental Cleanup		4,868,482			4,868,482
37	- MN Electric E-002/GR-17-894					
38						
39	Electric Low Income Discount Program		161,842			161,842
40	and PowerON Program					
41	- MN Electric E-002/GR-15-826					
42	- MN Electric E-002/M-04-1956					
43						
44	TOTAL	3,297,860,533	1,583,926,132		1,319,336,923	3,562,449,742

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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	North Dakota Service Quality Program		22,524			22,524
2	- ND Docket PU-10-657					
3	- ND Docket PU-11-55					
4	- ND Docket PU-12-813					
5						
6	South Dakota Fuel Clause Adjustment Charge		22,966			22,966
7	- SD Docket EL-14-058					
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						
41						
42						
43						
44	TOTAL	3,297,860,533	1,583,926,132		1,319,336,923	3,562,449,742

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 1 Column: d

Accounts charged:	
456	\$44,022,437
908	101,632,298
Total	\$145,654,735

Schedule Page: 232 Line No.: 7 Column: d

Accounts charged:	
431	\$21,509
495	5,634,920
908	17,338,389
Total	\$22,994,818

Schedule Page: 232 Line No.: 19 Column: d

Accounts charged:	
282	\$90,119,022
283	1,046,532
Total	\$91,165,554

Schedule Page: 232 Line No.: 30 Column: d

Accounts charged:	
254	\$106,615
407.4	1,313,483
Total	\$1,420,098

Schedule Page: 232 Line No.: 33 Column: d

Accounts charged:	
254	\$3,344,222
407.4	84,860,604
Total	\$88,204,826

Schedule Page: 232.1 Line No.: 5 Column: d

Accounts charged:	
254	\$5,901,120
557	759,187,252
Total	\$765,088,372

Schedule Page: 232.1 Line No.: 10 Column: d

Accounts charged:	
407.3	\$7,134,670
557	5,975,440
Total	\$13,110,110

Schedule Page: 232.1 Line No.: 13 Column: c

Accounts charged:	
517	\$4,795,186
519	971,510
520	8,143,123
523	334,482
524	2,932,126
528	746,445
529	19,947
530	27,756,332
531	2,599,776
532	18,661,825

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/06/2018	2017/Q4
FOOTNOTE DATA			

Total \$66,960,752

Schedule Page: 232.1 Line No.: 13 Column: d

Accounts charged:

517	\$5,145,351
519	1,068,889
520	7,070,502
523	277,765
524	2,959,099
528	1,224,099
529	68,263
530	22,976,325
531	3,901,169
532	18,230,684
Total	<u>\$62,922,146</u>

Schedule Page: 232.1 Line No.: 36 Column: d

Accounts charged:

407.4	\$6,030,795
856	594,033
863	227,292
870	527
874	3,553,320
880	123,202
887	39,452
892	3,733
893	12,524
Total	<u>\$10,584,878</u>

Schedule Page: 232.2 Line No.: 25 Column: f

Electric	\$134,450,188
Gas	6,105,073
Total	<u>\$140,555,261</u>
Reserve	(7,494,608)
	<u>\$133,060,653</u>

The total related to nonplant excess ADIT is \$140,555,261. This amount would be included as an increase to rate base for purposes of calculating the NSP companies formula rates, as applicable.

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	IPP Power Contract Billing	849,340	25,043	555	26,519	847,864
2	Adjustments					
3						
4	Conservation and Energy	46,523,279	33,459,111	182.3	48,368,493	31,613,897
5	Management Program Costs					
6	Minnesota Electric Incentive					
7	(Docket E-002/M-17-259)					
8						
9	Conservation and Energy	5,899,864	3,290,656	182.3	6,145,750	3,044,770
10	Management Program Costs					
11	Minnesota Gas Incentive					
12	(Docket G-002/M-17-258)					
13						
14	Federal and State Income	1,821,105	1,182,991	409.1	1,330,262	1,673,834
15	Taxes Receivable					
16						
17	Federal and State Income	3,728,323	573,882			4,302,205
18	Tax Interest Receivable					
19						
20	Debt Issuance Costs	272,501	3,251,667	181	3,520,168	4,000
21						
22	2016 Minnesota Electric Retail	2,226,667		928	556,675	1,669,992
23	Rate Case					
24	- Amortized through Dec. 2019					
25	(Docket E-002/GR-15-826)					
26						
27	North Dakota Electric	865,584	1,001,261			1,866,845
28	Retail Rate Case-Demand Study					
29	and Generation Restack					
30	(Docket PU-12-813)					
31						
32	2014 South Dakota Electric	119,193		928	119,193	
33	Retail Rate Case					
34	- Amortized through Dec. 2017					
35	(Docket EL14-058)					
36						
37	Future South Dakota Electric	113,169				113,169
38	Retail Rate Case					
39	(Docket EL 14-058)					
40						
41	Notes Receivable - 3rd Party	200,295		142	16,000	184,295
42						
43	2018 Minnesota Gas Retail Rate		8,279			8,279
44	Case					
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	62,619,320				46,922,173

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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	2018 South Dakota Electric Reta		3,826			3,826
2	Rate Case					
3						
4	Prepays - Facility Fees		4,132,829	921	2,543,632	1,589,197
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						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	62,619,320				46,922,173

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 Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric - Plant	306,154,752	183,100,260
3	Electric - Non-Plant	634,722,776	523,050,699
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	940,877,528	706,150,959
9	Gas		
10		39,870,049	26,114,354
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	39,870,049	26,114,354
17	Other (Specify)	57,020,275	50,833,875
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,037,767,852	783,099,188

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 2 Column: c

	Balance at Beginning of Year	Balance at End of Year
Electric Plant Related Only:		
Electric Distribution Plant	\$88,139,293	\$103,451,043
Electric General Plant	333,318	655,637
Electric Intangible Plant	5,824,660	4,816,525
Electric Nuclear Fuel	24,599,341	25,783,915
Electric Nuclear Production Plant	84,738,674	69,335,295
Electric Production Plant	45,376,009	43,725,916
Electric Transmission Plant	39,849,355	40,269,071
Electric Transmission - Production Plant	578,380	549,419
Common (Allocation to Electric)	610,759	687,606
Regulatory Difference - Effect of Rate Changes	(816,642)	(115,176,052)
Regulatory Difference - Investment Tax Credit Gross-Up	16,921,605	9,001,885
Total Electric Plant Related Only	<u>\$306,154,752</u>	<u>\$183,100,260</u>

Schedule Page: 234 Line No.: 8 Column: c

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	\$140,266,767	\$138,181,662
Bad Debts	7,559,768	5,646,935
Customer Advances	332,802	278,876
Deferred Connection Fees - CIAC	79,759,526	94,761,029
Deferred Rent	4,457,496	3,015,157
Deferred Revenue	1,214,749	639,619
Economic Development Securities - Write-Off	227,470	109,754
Electric Vehicle Credit	6,944	6,968
Employee Incentive Plans	7,045,573	4,105,569
Employee Stock Ownership Program Dividends	6,295,359	6,605,695
End of Life Nuclear Fuel Amortization	24,599,341	25,783,915
Environmental Remediation	91,732	49,186
Federal Net Operating Loss	304,695,697	120,032,866
Fuel Tax Credit - Income Addback	16,548	7,943
Inventory Reserve	893,862	1,092,553
Investment Tax Credit	1,737,177	452,260
Investment Tax Credit Grant	1,239,514	0
Litigation Reserve	182,107	118,760
Medical Deductions - Self Insured	841,145	524,230
Monticello Extended Power Uprate Writedown	38,795,994	23,663,250
New Hire Retention Credit	52,102	51,697
Nonplant Accumulated Deferred Income Tax Rate Change	0	14,975,075
North Dakota Investment Tax Credit	64,345,539	85,716,216
North Dakota Investment Tax Credit - Valuation Allowance	(59,421,769)	(81,049,114)
North Dakota Investment Tax Credit - Federal Gross-Up	2,651,261	1,240,622
Performance Recognition Awards	38,047	12,053
Post Employment Benefits - Retiree Medical	22,584,681	13,578,683
Post Employment Benefits - Long Term Disability	6,292,255	4,233,751
Purchased Power Capacity	82,558	56,915
Rate Refund	21,093,779	6,601,567
Regulatory Asset/Liability - Prairie Island Extended	1,835,785	1,126,653
Power Uprate Cancellation		
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	0	4,040,755
Regulatory Asset/Liability - Transmission Cost Recovery	0	2,109,931

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Rider

Regulatory Asset/Liability - Windsources	95,196	0
Regulatory Difference - Effect of Rate Changes	(816,642)	(115,176,052)
Regulatory Difference - Investment Tax Credit Gross-Up	16,921,605	9,001,885
Research and Experimentation Credit	44,940,397	52,073,882
Sale of Emission Allowances	43,566	22,531
Section 174 - Section 59(e) Adjustment	0	15,120,000
Severance Accrual	74,421	67,113
Solar Rewards Program	8,068,952	7,464,420
South Dakota Infrastructure Tracker	201,799	289,335
State Research Credit	4,082,247	5,877,139
State Research Credit - Valuation Allowance	(949,735)	(1,102,028)
State Tax Deduction Cash vs. Accrual	695,519	268,124
Vacation Accrual	7,439,978	5,010,118
Wind Production Tax Credit	180,228,683	249,437,361
Workers Compensation	37,733	26,100
Total Electric	<u>\$940,877,528</u>	<u>\$706,150,959</u>

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 related to postretirement employee benefits and regulatory differences related to income taxes. An adjustment is made to include the regulatory asset balance related to nonplant accumulated deferred income tax rate change.

Schedule Page: 234 Line No.: 16 Column: c

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	\$2,565,968	\$2,706,851
Bad Debts	580,954	333,562
Deferred Connection Fees - CIAC	10,029,621	10,300,853
Deferred Rent	375,002	230,091
Deferred Revenue	100,905	48,694
Economic Development Securities - Write-Off	22,869	6,483
Electric Vehicle Credit	556	532
Employee Incentive Plans	601,852	341,750
Employee Stock Ownership Program Dividends	1,989,928	2,228,951
Environmental Remediation	4,699,435	5,257,966
Federal Net Operating Loss	13,840,632	6,194,438
Fuel Tax Credit - Income Addback	1,324	606
Inventory Reserve	75,199	83,374
Litigation Reserve	13,995	7,015
Lower of Cost or Market on Gas Inventories	168,070	332,033
Medical Deduction - Self Insured	83,910	43,637
New Hire Retention Credit	3,898	4,303
Nonplant Accumulated Deferred Income Tax Rate Change	0	737,417
Performance Recognition Awards	3,250	1,003
Post Employment Benefits - Retiree Medical	1,929,246	1,130,297
Post Employment Benefits - Long Term Disability	537,502	352,420
Regulatory Difference - Effect of Rate Changes	488,429	(6,317,355)
Regulatory Difference - Investment Tax Credit Gross-Up	1,080,848	510,797
Section 174 - Section 59(e) Adjustment	0	1,153,831
Severance Accrual	6,357	5,587
State Tax Deduction Cash vs. Accrual	31,533	0
Vacation Accrual	635,543	417,045

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Workers' Compensation	3,223	2,173
Total Gas	\$39,870,049	\$26,114,354

Schedule Page: 234 Line No.: 17 Column: c

Other:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	(\$207)	\$26
Contributions Carryover	5,534,921	426,123
Deferred Compensation Plan Reserve	5,143,407	4,421,661
Federal Alternative Minimum Tax Credit	0	933,754
Federal Net Operating Loss	10,378,683	7,787,843
Low Income Housing Credit	3,344,790	3,344,790
Minnesota Alternative Minimum Tax Credit	0	143,158
Minnesota Net Operating Loss	14,707,436	21,393,981
North Dakota Net Operating Loss	957,530	669,266
Nonqualified Pension Plans	967,496	594,277
Other Comprehensive Income	14,378,872	9,672,015
Partnership Passthrough	473,559	320,915
Performance Share Plan	1,108,669	979,135
Regulatory Difference - Effect of Rate Changes	(16)	(16)
State Tax Deduction Cash vs. Accrual	25,135	144,832
Wisconsin Net Operating Loss	0	2,115
Total Other	\$57,020,275	\$50,833,875

Schedule Page: 234 Line No.: 18 Column: c

Refer to FERC page 232 for NSPM's regulatory asset related to nonplant excess ADIT.

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	Common Stock			
2	-All NSP-Minnesota common stock is owned by			
3	parent, Xcel Energy Inc.	5,000,000	0.01	
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				
41				
42				

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)	
						1
						2
1,000,000	10,000					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
						41
						42

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	Account 211 - Miscellaneous Paid-in Capital	
2	Contribution of capital by parent company	3,100,951,102
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	3,100,951,102

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	--	--

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		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- In column (a), for new issues, give Commission authorization numbers and dates.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
- 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.
- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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		
2	FIRST MORTGAGE BONDS SERIES DUE:		
3			
4	5.25% March 1, 2018 First Mortgage Bonds	500,000,000	4,815,362
5			1,520,000 D
6			
7	2.15% Aug. 15, 2022 First Mortgage Bonds	300,000,000	3,088,686
8			456,000 D
9			
10	7.125% July 1, 2025 First Mortgage Bonds	250,000,000	1,898,288
11			2,330,000 D
12			
13	6.50% March 1, 2028 First Mortgage Bonds	150,000,000	1,474,427
14			1,761,001 D
15			
16	5.25% July 15, 2035 First Mortgage Bonds	250,000,000	3,032,114
17			485,000 D
18			
19	6.25% June 1, 2036 First Mortgage Bonds	400,000,000	4,877,065
20			1,404,000 D
21			
22	6.20% July 1, 2037 First Mortgage Bonds	350,000,000	4,336,843
23			1,988,000 D
24			
25	5.35% Nov. 1, 2039 First Mortgage Bonds	300,000,000	4,153,918
26			570,000 D
27			
28	4.85% Aug. 15, 2040 First Mortgage Bonds	250,000,000	3,019,146
29			707,500 D
30			
31	3.40% Aug 15, 2042 First Mortgage Bonds	500,000,000	6,272,718
32			3,820,000 D
33	TOTAL	5,500,000,000	96,632,555

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			
2	2.60% May 15, 2023 First Mortgage Bonds	400,000,000	4,524,626
3			732,000 D
4			
5	4.125% May 15, 2044 First Mortgage Bonds	300,000,000	3,821,358
6			873,000 D
7			
8	3.60% Sep 15, 2047 First Mortgage Bond	600,000,000	8,770,168
9			5,982,000 D
10			
11	2.20% Aug. 15, 2020 First Mortgage Bonds	300,000,000	3,072,956
12			552,000 D
13			
14	4.00% Aug. 15, 2045 First Mortgage Bonds	300,000,000	3,897,956
15			4,899,000 D
16			
17	3.60% May 15, 2046 First Mortgage Bonds	350,000,000	5,404,423
18			2,093,000 D
19	SUBTOTAL - ACCOUNT 221	5,500,000,000	96,632,555
20			
21	ACCOUNT 224		
22	OTHER LONG TERM DEBT		
23			
24	Right of Way debt		
25			
26	SUBTOTAL - ACCOUNT 224		
27			
28	Interest on Debt to Associated Companies		
29			
30			
31			
32			
33	TOTAL	5,500,000,000	96,632,555

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
3/18/2008	3/1/2018	3/18/2008	3/1/2018		19,926,364	4
						5
						6
8/13/2012	8/15/2022	8/13/2012	8/15/2022	300,000,000	6,450,000	7
						8
						9
7/1/1995	7/1/2025	7/1/1995	7/1/2025	250,000,000	17,812,500	10
						11
						12
3/1/1998	3/1/2028	3/1/1998	3/1/2028	150,000,000	9,750,000	13
						14
						15
7/21/2005	7/15/2035	7/21/2005	7/15/2035	250,000,000	13,125,000	16
						17
						18
5/25/2006	6/1/2036	5/25/2006	6/1/2036	400,000,000	24,455,460	19
						20
						21
6/26/2007	7/1/2037	6/26/2007	7/1/2037	350,000,000	21,610,352	22
						23
						24
11/17/2009	11/1/2039	11/17/2009	11/1/2039	300,000,000	16,156,993	25
						26
						27
8/11/2010	8/15/2040	8/11/2010	8/15/2040	250,000,000	12,125,000	28
						29
						30
8/13/2012	8/15/2042	8/13/2012	8/15/2042	500,000,000	18,496,479	31
						32
				5,000,035,044	221,487,501	33

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
5/20/2013	5/15/2023	5/20/2013	5/15/2023	400,000,000	10,400,000	2
						3
						4
5/13/2014	5/15/2044	5/13/2014	5/15/2044	300,000,000	12,375,000	5
						6
						7
09/13/2017	09/15/2047	09/13/2017	09/15/2047	600,000,000	6,480,000	8
						9
						10
8/11/2015	8/15/2020	8/11/2015	8/15/2020	300,000,000	6,600,000	11
						12
						13
8/11/2015	8/15/2045	8/11/2015	8/15/2045	300,000,000	12,000,000	14
						15
						16
5/31/2016	5/15/2046	5/31/2016	5/15/2046	350,000,000	12,600,000	17
						18
				5,000,000,000	220,363,148	19
						20
						21
						22
						23
				35,044		24
						25
				35,044		26
						27
					1,124,353	28
						29
						30
						31
						32
				5,000,035,044	221,487,501	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 4 Column: h
5.25% March 1, 2018 First Mortgage Bond was called on September 29, 2017.

Schedule Page: 256 Line No.: 4 Column: i

interest at stated rate	\$19,541,667
interest at swap loss	\$384,698
	\$19,926,364

Schedule Page: 256 Line No.: 19 Column: i

Interest at stated rate	\$25,000,000
Interest at swap gain	(\$544,540)
	\$24,455,460

Schedule Page: 256 Line No.: 22 Column: i

Interest at stated rate	\$21,700,000
Interest at swap gain	(\$89,647.62)
	\$21,610,352

Schedule Page: 256 Line No.: 25 Column: i

Interest at stated rate	\$16,050,000
Interest at swap loss	\$106,993
	\$16,156,993

Schedule Page: 256 Line No.: 31 Column: i

Interest at stated rate	\$17,000,000
Interest at swap loss	\$1,496,479
	\$18,496,479

Schedule Page: 256.1 Line No.: 8 Column: a
Minnesota Public Utilities Commission case no. E,G002/S-16-887. Order dated Mar. 21, 2017.

NSPMN issued \$600 million of 3.60 percent First Mortgage Bond due Sep. 15, 2047. NSPMN used a portion of the net proceeds from the sale to repay redemption of \$500M 5.25 percent First Mortgage Bonds due Mar. 1, 2018 and for other general corporate purposes.

Schedule Page: 256.1 Line No.: 24 Column: h

	Balance Dec. 31, 2016	Additions	Reductions	Balance Dec. 31, 2017
Right of Way debt	\$ 22,518	\$22,278	\$ (9,752)	\$ 35,044

Schedule Page: 256.1 Line No.: 28 Column: i

Xcel Energy Services Inc	\$ 820,973
NSP Nuclear Corp	15,993
Money Pool	287,387
	\$ 1,124,353

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 filed, 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)	490,121,306
2		
3		
4	Taxable Income Not Reported on Books	
5		51,476,250
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		903,997,414
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-87,680,564
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-1,562,637,622
21		
22	Equity in Earnings of Subsidiary Companies	126,890
23		
24	Total Income Tax Expense	199,702,604
25		
26		
27	Federal Tax Net Income	-4,893,722
28	Show Computation of Tax:	
29	Federal Income Tax at 35 percent	-1,712,803
30	Other	19,162,925
31	Total Federal Income Tax Payable	17,450,122
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 5 Column: b

TAXABLE INCOME NOT REPORTED ON BOOKS:

Contributions in Aid of Construction	\$44,709,833
Solar Rewards Program	6,766,417
	<u>\$51,476,250</u>

Schedule Page: 261 Line No.: 10 Column: b

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Avoided Cost Interest	\$15,116,620
Bad Debts	1,310,660
Book Amortization - Computer Software	47,159,499
Book Amortization - Other	12,863,565
Book Depreciation	589,966,223
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	129,000
Book Rent Expense - Capitalized for Tax - Railcars	438,465
Capitalization of Software Expense - Books	917,788
Clearing Account Book Expense	19,658,961
Contributions Carryover	1,516,124
Deferred Compensation Plan Reserve	3,116,242
Employee Stock Ownership Plan Dividends	1,903,734
Environmental Remediation	7,130,750
Inventory Reserve	1,806,965
Lobbying Expenses	1,647,000
Meals & Entertainment	1,047,000
Nuclear Decommissioning	20,371,744
Nuclear Fuel Expense	114,383,793
Penalties	64,652
Pension and Benefit Capitalized	7,715,373
Performance Share Plan	764,358
Prairie Island Extended Power Uprate Writedown Amortization	2,888,815
Prepaid Advertising	1
PUCIP Adjustment	7,732,814
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	15,655,976
Regulatory Asset/Liability - Transmission Cost Recovery Rider	3,431,165
Section 174 - Section 59(e) Adjustment	24,352,323
Severance Accrual	60,527
South Dakota Infrastructure Tracker	534,465
Suite and Entertainment Tickets	232,000
Tax Expense - Spent Fuel Isolation Devices	80,680
Workers' Compensation	132
	<u>\$903,997,414</u>

Schedule Page: 261 Line No.: 15 Column: b

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:

Allowance for Funds During Construction (AFDC) - Equity (Non-Conservation Improvement Program)	(\$32,663,152)
Deferred Revenue - Investment Tax Credit (ITC) Grant	(173,548)
Gain/(Loss) on Dispositions (Book)	(1,021,764)
Insurance Fund Income (Cash Value)	(3,372,264)
Rate Surcharge	(50,449,836)
	<u>(\$87,680,564)</u>

Schedule Page: 261 Line No.: 20 Column: b

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/06/2018	2017/Q4
FOOTNOTE DATA			

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

Allowance for Funds During Construction (AFDC) - Debt (Non-Conservation Improvement Program)	(\$16,937,021)
Book Unamortized Cost of Reacquired Debt	(6,362,276)
Deferred Fuel Costs	(1,239,879)
Deferred Rent	(306,771)
Deferred Revenue	(778,066)
Electric Vehicle Charging Tariff	(101,423)
Employee Incentive Plans	(2,934,343)
Employee Retention	(87,161)
External Qualified Nuclear Decommissioning Fund	(20,371,744)
Federal Net Operating Loss	(208,709,547)
Fuel Hedging	(1,823)
Gain/(Loss) on Dispositions (Tax)	(5,303,185)
Internally Developed Software	(451,851)
Interest Expense - Capital Leases	(141,292)
Interest Income/Expense on Disputed Tax	(3,584,469)
Litigation Reserve	(33,500)
Low Income Discount Program	(161,842)
Mark to Market Adjustment	(2,607,368)
Medical Deduction - Self Insured	(27,364)
Nonqualified Pension Plan	(284,516)
Partnership Passthrough	(10,600)
Pension Expense	(35,252,582)
Performance Recognition Awards	(54,839)
Post Employment Benefits - Retiree Medical	(7,794,194)
Post Employment Benefits - Long Term Disability	(434,732)
Prepaid Insurance	(4,538,851)
Rate Case/Restructuring Expense	(341,012)
Rate Refund	(28,250,966)
Regulatory Asset - Gas Safety Deferrals	(10,941,614)
Regulatory Asset - Nuclear Refueling Outage Costs	(4,038,605)
Regulatory Asset - Prairie Island Extended Power Uprate Cancellation	(494,225)
Regulatory Asset - Property Tax	(16,360,244)
Regulatory Asset/Liability - Transmission Attach O	(1,183,004)
Regulatory Asset/Liability - Windsource	(475,517)
Regulatory Reserve - Environmental	(9,995,248)
Renewable Energy Standard/Credit	(24,139)
Repair Expenditures	(59,654,839)
Sale of Emission Allowances	(26,695)
Section 174	(31,200,000)
State Tax Deduction	(14,905,090)
Tax Amortization - Monticello Rerate	(6,295,644)
Tax Amortization - Computer Software	(48,338,101)
Tax Amortization - Pollution Control Facilities	(519,213)
Tax Depreciation	(949,901,787)
Tax Expense - Ash Ponds and Landfills	(200,838)
Tax Removal Cost Over Book	(60,481,463)
Vacation Accrual	(498,139)
	(\$1,562,637,622)

Schedule Page: 261 Line No.: 31 Column: b

Northern States Power Company (a Minnesota corporation) is a member of an affiliated group which will file a consolidated federal income tax return for the year 2017. The other members of the affiliated group and the federal income tax provision of each are:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Xcel Energy Inc.	(\$67,591,052)
NSP Nuclear Corporation	3,172
United Power and Land Company	(119,255)
Northern States Power Company (Wisconsin) and Subsidiaries	3,506,112
Public Service Company of Colorado and Subsidiaries	41,359,335
Southwestern Public Service Company	(20,028,344)
Nicollet Holdings Company, LLC and Subsidiaries	(157,595)
Nicollet Projects Holdings Company, LLC and Subsidiaries	(2,940)
Xcel Energy Communications Group Inc. and Subsidiaries	106,783
Xcel Energy Markets Holdings Inc. and Subsidiaries	310,840
Xcel Energy International Inc.	(10,835)
Xcel Energy Retail Holdings Inc. and Subsidiaries	(326,529)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(168,863)
Xcel Energy Ventures Inc. and Subsidiaries	366,955
Xcel Energy Venture Holdings, Inc. and Subsidiaries	(143,164)
Xcel Energy Wholesale Group Inc. and Subsidiaries	(1,946,252)
Xcel Energy WYCO Inc.	6,600,530
WestGas Interstate, Inc.	51,113
Xcel Energy Services Inc.	11,859,462

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.

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 known, 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES					
2	Income		17,115,806	29,810,343	56,126,441	-32,831,386
3	Income Tax Adjustment			-12,360,221		12,360,221
4						
5	FICA 2017			33,306,752	31,035,657	
6	FICA 2016	2,179,108			2,179,108	
7						
8	Unemployment 2017			193,435	183,885	
9	Unemployment 2016	2,692			2,692	
10						
11	SUBTOTAL	2,181,800	17,115,806	50,950,309	89,527,783	-20,471,165
12						
13	STATE TAXES					
14	MINNESOTA					
15	Income		8,350,496	14,596,230	14,988,263	5,974,000
16	Income Tax Adjustment			1,033,782		-1,033,782
17						
18	Unemployment 2017			3,768,597	3,563,370	
19	Unemployment 2016	73,339			73,339	
20						
21	Real Estate 2017			117,557,000		
22	Real Estate 2016	110,470,000		-4,913,736	105,556,264	
23	Real Estate 2017 MN Stmt			5,561,793		-5,561,793
24						
25	Personal Property 2017			92,543,000		
26	Personal Property 2016	93,930,000		-46,895	93,883,105	
27						
28	Use 2017			15,103,233	13,447,720	
29	Use 2016	3,793,225		-2,852,198	941,027	
30						
31	SUBTOTAL	208,266,564	8,350,496	242,350,806	232,453,088	-621,575
32						
33	STATE TAXES					
34	NORTH DAKOTA					
35	Income	169,938		136,286	3,376	-360,371
36	Income Tax Adjustment			11,504		-11,504
37						
38	Unemployment 2017			18,386	17,714	
39	Unemployment 2016	195			195	
40						
41	TOTAL	219,084,491	25,549,302	305,435,580	331,568,444	-21,482,021

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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Personal Property 2017			5,100,000		1,245,000
2	Personal Property 2016	4,650,000		668,736	4,073,736	-1,245,000
3						
4	Use 2017			429,290	268,229	
5	Use 2016	10,005		-1,248	8,758	
6						
7	SUBTOTAL	4,830,138		6,362,954	4,372,008	-371,875
8						
9	STATE TAXES					
10	SOUTH DAKOTA					
11	Unemployment 2017			18,584	25,790	
12	Unemployment 2016	-7,022			-7,022	
13						
14	Personal Property 2017			4,100,000		
15	Personal Property 2016	3,800,000		-80,230	3,719,770	
16	Personal Property FCA			-410,959	-410,959	
17						
18	Use 2017			987,753	834,157	
19	Use 2016	-1,109		11,215	10,106	
20						
21	SUBTOTAL	3,791,869		4,626,363	4,171,842	
22						
23	STATE TAXES					
24	KANSAS					
25	Personal Property 2016			813,259	813,259	
26						
27	SUBTOTAL			813,259	813,259	
28						
29	STATE TAXES					
30	WISCONSIN					
31	Income		83,000	13,304	-87,102	-17,406
32						
33	Unemployment 2016	-313		1,065	1,894	
34						
35	SUBTOTAL	-313	83,000	14,369	-85,208	-17,406
36						
37	OTHER					
38	Colorado Unemployment					
39	Georgia Unemployment 2017			11	84	
40	Denver Occ'l Priviledge	-4			8	
41	TOTAL	219,084,491	25,549,302	305,435,580	331,568,444	-21,482,021

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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Property Tax on Rail Car			20,000	3,634	
2	Property Tax on Rail Car	14,437		-11,880	2,557	
3	Other			308,836	308,836	
4	Pennsylvania Income			553	553	
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						
41	TOTAL	219,084,491	25,549,302	305,435,580	331,568,444	-21,482,021

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
	76,263,290	26,941,708			2,868,635	2
		-14,750,882			2,390,661	3
						4
2,271,095		28,194,270			5,112,482	5
						6
						7
9,550		172,849			20,586	8
						9
						10
2,280,645	76,263,290	40,557,945			10,392,364	11
						12
						13
						14
	2,768,529	9,618,042			4,978,188	15
		430,405			603,377	16
						17
205,227		2,520,535			1,248,062	18
						19
						20
117,557,000		116,180,000			1,377,000	21
		-4,836,298			-77,438	22
		5,561,793				23
						24
92,543,000		76,393,000			16,150,000	25
		-50,039			3,144	26
						27
1,655,513					15,103,233	28
					-2,852,198	29
						30
211,960,740	2,768,529	205,817,438			36,533,368	31
						32
						33
						34
	57,523	742,068			-605,782	35
		-515			12,019	36
						37
672		11,837			6,549	38
						39
						40
225,009,647	79,089,342	255,564,901			49,870,679	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more than 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 (i) 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)	
6,345,000		3,812,000			1,288,000	1
		695,008			-26,272	2
						3
161,061					429,290	4
					-1,248	5
						6
6,506,733	57,523	5,260,398			1,102,556	7
						8
						9
						10
-7,206		11,789			6,795	11
						12
						13
4,100,000		4,100,000				14
		-80,230				15
		-410,959				16
						17
153,596					987,753	18
					11,215	19
						20
4,246,390		3,620,600			1,005,763	21
						22
						23
						24
					813,259	25
						26
					813,259	27
						28
						29
						30
		9,183			4,121	31
						32
-1,142		655			410	33
						34
-1,142		9,838			4,531	35
						36
						37
						38
-73		7			4	39
-12		13,480			-13,480	40
225,009,647	79,089,342	255,564,901			49,870,679	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more than 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 (i) 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)	
16,366					20,000	1
					-11,880	2
		285,195			23,641	3
					553	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
225,009,647	79,089,342	255,564,901			49,870,679	41

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
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)	\$ (440,357)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	(1,856,098)
Federal tax benefit (accrual and cash) for net operating loss carryback accrued in other accounts receivable (143)	(30,534,931)
	<u>\$ (32,831,386)</u>

Schedule Page: 262 Line No.: 2 Column: l

Gas (Account No. 409.1)	\$ 741,524
Other income and deductions (Account No. 409.2)	2,127,111
	<u>\$ 2,868,635</u>

Schedule Page: 262 Line No.: 3 Column: f

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ 7,036,463
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	5,323,759
Rounding	(1)
	<u>\$ 12,360,221</u>

Schedule Page: 262 Line No.: 3 Column: l

Gas (Account No. 409.1)	\$ (9,718)
Other income and deductions (Account No. 409.2)	2,400,379
	<u>\$ 2,390,661</u>

Schedule Page: 262 Line No.: 5 Column: l

Gas (Account No. 408.1)	\$ 2,581,054
Other income and deductions (Account No. 408.2)	60,048
Other	2,471,380
	<u>\$ 5,112,482</u>

Schedule Page: 262 Line No.: 8 Column: l

Gas (Account No. 408.1)	\$ 15,827
Other income and deductions (Account No. 408.2)	359
Other	4,400
	<u>\$ 20,586</u>

Schedule Page: 262 Line No.: 15 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	\$ 301,068
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	5,672,932
	<u>\$ 5,974,000</u>

Schedule Page: 262 Line No.: 15 Column: l

Gas (Account No. 409.1)	\$ 314,225
Other income and deductions (Account No. 409.2)	4,663,963
	<u>\$ 4,978,188</u>

Schedule Page: 262 Line No.: 16 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ (660,780)
State income tax expense (409.1 and 409.2) accrued liability for uncertain	(373,002)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

tax positions (253) \$ (1,033,782)

Schedule Page: 262 Line No.: 16 Column: I	
Gas (Account No. 409.1)	\$ (2,422)
Other income and deductions (Account No. 409.2)	605,799
	<u>\$ 603,377</u>

Schedule Page: 262 Line No.: 18 Column: I	
Gas (Account No. 408.1)	\$ 231,681
Other income and deductions (Account No. 408.2)	72,022
Other	944,359
	<u>\$ 1,248,062</u>

Schedule Page: 262 Line No.: 21 Column: I	
Gas (Account No. 408.1)	\$ 1,317,000
Other income and deductions (Account No. 408.2)	60,000
	<u>\$ 1,377,000</u>

Schedule Page: 262 Line No.: 22 Column: I	
Gas (Account No. 408.1)	\$ (77,438)

Schedule Page: 262 Line No.: 23 Column: f	
As part of the Minnesota 2016 Multi-Year Electric Rate Case (Docket E-002/GR-15-826) the MPUC approved a symmetrical true-up of actual property taxes for the years 2017-2019 to a baseline amount. Adjustment represents deferral of amount above/below baseline.	

Schedule Page: 262 Line No.: 25 Column: I	
Gas (Account No. 408.1)	\$ 16,144,000
Other income and deductions (Account No. 408.2)	6,000
	<u>\$ 16,150,000</u>

Schedule Page: 262 Line No.: 26 Column: I	
Gas (Account No. 408.1)	\$ 3,144

Schedule Page: 262 Line No.: 35 Column: f	
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	\$ (7,982)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	(352,389)
	<u>\$ (360,371)</u>

Schedule Page: 262 Line No.: 35 Column: I	
Gas (Account No. 409.1)	\$ 17,930
Other income and deductions (Account No. 409.2)	(623,712)
	<u>\$ (605,782)</u>

Schedule Page: 262 Line No.: 36 Column: f	
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ (12,651)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	1,147
	<u>\$ (11,504)</u>

Schedule Page: 262 Line No.: 36 Column: I	
Gas (Account No. 409.1)	\$ (44)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Other income and deductions (Account No. 409.2)	12,063
	\$ 12,019

Schedule Page: 262 Line No.: 38 Column: I	
Gas (Account No. 408.1)	\$ 1,344
Other income and deductions (Account No. 408.2)	29
Other	5,176
	\$ 6,549

Schedule Page: 262.1 Line No.: 1 Column: f	
North Dakota Wind Production tax - production year 2016, tax reported and billed in 2017, paid in 2018.	

Schedule Page: 262.1 Line No.: 1 Column: I	
Gas (Account No. 408.1)	\$ 1,288,000

Schedule Page: 262.1 Line No.: 2 Column: f	
North Dakota Wind Production tax - production year 2016, tax reported and billed in 2017, paid in 2018.	

Schedule Page: 262.1 Line No.: 2 Column: I	
Gas (Account No. 408.1)	\$ (26,272)

Schedule Page: 262.1 Line No.: 11 Column: I	
Gas (Account No. 408.1)	\$ 1,084
Other income and deductions (Account No. 408.2)	29
Other	5,682
	\$ 6,795

Schedule Page: 262.1 Line No.: 16 Column: a	
South Dakota Personal Property Tax collected through the Fuel Clause Adjustment. See page 232.	

Schedule Page: 262.1 Line No.: 25 Column: I	
Gas (Account No. 408.1)	\$ 813,259

Schedule Page: 262.1 Line No.: 31 Column: f	
Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid in capital (207)	
	\$ (17,406)

Schedule Page: 262.1 Line No.: 31 Column: I	
Other income and deductions (Account No. 409.2)	\$ 4,121

Schedule Page: 262.1 Line No.: 33 Column: I	
Gas (Account No. 408.1)	\$ 62
Other income and deductions (Account No. 408.2)	2
Other	346
	\$ 410

Schedule Page: 262.1 Line No.: 39 Column: I	
Gas (Account No. 408.1)	\$ 1
Other	3
	\$ 4

Schedule Page: 262.1 Line No.: 40 Column: I	
Gas (Account No. 408.1)	\$ 1,232
Other income and deductions (Account No. 408.2)	14
Other	(14,726)
	\$ (13,480)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 262.2 Line No.: 1 Column: a

Property tax on railroad cars used to transport coal from mines to electric generating plants.

Schedule Page: 262.2 Line No.: 2 Column: a

Property tax on railroad cars used to transport coal from mines to electric generating plants.

Schedule Page: 262.2 Line No.: 3 Column: l

Gas (Account No. 408.1) \$ 23,641

Schedule Page: 262.2 Line No.: 4 Column: l

Other income and deductions (Account No. 409.2) \$ 553

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%	61,623			411.4	4,529	
4	7%						
5	10%	20,767,906			411.4	1,277,239	
6	30%	1,673,767			411.4	97,312	
7							
8	TOTAL	22,503,296				1,379,080	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	1,679			411.4	65	
13	10%	1,560,036			411.4	263,197	
14	TOTAL	1,561,715				263,262	
15							
16	4%	5,713			411.4	445	
17	10%	104,508			411.4	4,841	
18	TOTAL	110,221				5,286	
19							
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							
48	Utility & Non-Utili	24,175,232				1,647,628	

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
57,094	55 Years		3
			4
19,490,667	51 Years		5
1,576,455	21 Years		6
			7
21,124,216			8
			9
			10
			11
1,614	68 Years		12
1,296,839	43 Years		13
1,298,453			14
			15
5,268	55 Years		16
99,667	55 Years		17
104,935			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
22,527,604			48

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 266 Line No.: 8 Column: h

Accumulated Deferred Investment Tax Credits (Account 255). The formula excludes this account because the Company has chosen to utilize the amortization of tax credits against taxable income, that is, income tax expense is reduced by the amount of the amortized investment tax credit.

Schedule Page: 266 Line No.: 18 Column: h

(a) Common Allocation

Electric - 92.43%	\$ 96,796
Gas - 7.57%	8,139
	\$104,935

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Unfunded Nonqualified Pension	5,609,250	232	1,687,377	1,473,238	5,395,111
2	Benefit Costs					
3						
4	Deferred Compensation					
5	Employees	6,799,539	146	577,167	4,142,467	10,364,839
6	Employees (Wealth Op)	5,816,251	232	534,731	85,674	5,367,194
7						
8	Postemployment Benefit-Injury	16,752,082	Various	1,977,618	1,542,886	16,317,350
9	Compensation					
10						
11	Environmental & Regulatory	3,663,810	242	200,746		3,463,064
12	Reserves					
13						
14	Nuclear Waste Strategy Coalition	101,242	232	83,965	67,625	84,902
15						
16	Renewable Development Fund	40,451,000	232	20,262,403	25,600,000	45,788,597
17	Obligations					
18						
19	Long-Term Income Tax & Interest	11,507,167	431	4,437,614		7,069,553
20	Payable					
21						
22	Deposits-Landfill Power	296,025			286	296,311
23						
24	Customer Prepayments	146,450	107	1,735,359	2,137,535	548,626
25						
26	Deferred Revenue	710,380	Various	2,591,263	4,329,864	2,448,981
27						
28	Wholesale Merger Settlement	82,703				82,703
29						
30	Pre-Funded AFUDC					
31	Metro Emissions Reduction Rider	59,050,476	405	2,231,583		56,818,893
32	Mercury Emission Reduction Rider	543,459	405	55,577		487,882
33	Minnesota Transmission Cost	32,326,263	Various	2,588,396	1,155,002	30,892,869
34	Recovery Rider					
35	FERC Transmission	40,576,255	405	887,407	112,630	39,801,478
36	Renewable Energy Standards Rider	28,135,180	405	1,417,010		26,718,170
37	South Dakota Transmission	1,822,730	Various	40,633	62,075	1,844,172
38	Cost Recovery Rider					
39	North Dakota Transmission	1,174,124	Various	278,473	318,111	1,213,762
40	Cost Recovery Rider					
41						
42	NMC Long-Term Incentive	1,944,967			111,431	2,056,398
43						
44	Deferred Revenue-ITC Grant	1,990,376	405	185,609		1,804,767
45						
46	Mark-to-Market Adjustment	8,920,173			1,591,183	10,511,356
47	TOTAL	331,296,972		56,554,953	50,701,001	325,443,020

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Mankato/Cannon Falls Lease	41,804,014	Various	3,469,272	1,007,816	39,342,558
2	Normalization					
3						
4	Long-Term Payroll Tax Liability	1,640,320				1,640,320
5						
6	Coal Car Residual Value Deficit	1,565,850			660,322	2,226,172
7						
8	Nuclear Fuel Services	140,490	517	140,490		
9						
10	Sherco Unit 3 Insurance Settlement	5,395,458	107	4,569,799		825,659
11						
12	401 Nicollet Lease Credit	12,330,938	Various	6,602,461	6,302,856	12,031,333
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						
41						
42						
43						
44	** Footnote from page 106b					
45						
46						
47	TOTAL	331,296,972		56,554,953	50,701,001	325,443,020

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 8 Column: c

Accounts charged:	
131	\$1,226,593
232	751,025
Total	<u>\$1,977,618</u>

Schedule Page: 269 Line No.: 26 Column: c

Accounts charged:	
447	\$967,850
454	556,163
456	300,000
495	767,250
Total	<u>\$2,591,263</u>

Schedule Page: 269 Line No.: 33 Column: c

Accounts charged:	
405	\$555,487
419.1	1,318,792
432	714,117
Total	<u>\$2,588,396</u>

Schedule Page: 269 Line No.: 35 Column: d

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized amortization expense (405) amount is \$675,704

Schedule Page: 269 Line No.: 35 Column: e

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized Pre-funded AFUDC (Total Accounts Other Expenses - 432, Other Revenue - 419.1) amount is \$123,701

Schedule Page: 269 Line No.: 37 Column: c

Accounts charged:	
405	\$29,997
419.1	7,208
432	3,428
Total	<u>\$40,633</u>

Schedule Page: 269 Line No.: 39 Column: c

Accounts charged:	
405	\$17,455
419.1	176,663
432	84,355
Total	<u>\$278,473</u>

Schedule Page: 269.1 Line No.: 1 Column: c

Accounts charged:	
182.3	\$1,734,636
253	1,734,636
Total	<u>\$3,469,272</u>

Schedule Page: 269.1 Line No.: 12 Column: c

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Accounts charged:

146	\$757,896
233	5,844,565
Total	\$6,602,461

Schedule Page: 269.1 Line No.: 44 Column: a

The Form 1 reports the other deferred credits balances at the beginning of year and at the end of the year. Included in this account is the credit for pre-funded AFUDC on CWIP related to the specific transmission projects that are included in the formula. These are jurisdictional amounts. The net pre-funded AFUDC amount used in the Attachment O formula is a total NSP system number (unjurisdictionalized). The formula requires the Company to use a 13 month average balance in the determination of the adjustment to rate base related to this account.

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 relating 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)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	32,924,109	-2,082,132	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	32,924,109	-2,082,132	
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)	32,924,109	-2,082,132	
18	Classification of TOTAL			
19	Federal Income Tax	25,621,172	-1,622,834	
20	State Income Tax	7,302,937	-459,298	
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
						30,841,977	4
							5
							6
							7
						30,841,977	8
							9
							10
							11
							12
							13
							14
							15
							16
						30,841,977	17
							18
						23,998,338	19
						6,843,639	20
							21

NOTES (Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 272 Line No.: 8 Column: k

All amounts in columns b - k are related to Electric Steam Production Plant.

Accumulated Deferred Income Taxes (Account No. 281). 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 tax balances in the formula.

ACCUMULATED DEFERRED 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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	3,384,413,204	80,546,035	
3	Gas	216,819,565	8,272,350	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,601,232,769	88,818,385	
6	Non-Operating	24,553		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	3,601,257,322	88,818,385	
10	Classification of TOTAL			
11	Federal Income Tax	2,907,466,325	44,500,860	
12	State Income Tax	693,790,997	44,317,525	
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
			1,660,213,606		186,407,817	1,991,153,450	2
			104,724,965		1,231,277	121,598,227	3
							4
			1,764,938,571		187,639,094	2,112,751,677	5
-52,007						-27,454	6
							7
							8
-52,007			1,764,938,571		187,639,094	2,112,724,223	9
							10
-13,965			1,575,817,443		115,473,880	1,491,609,657	11
-38,042			189,121,128		72,165,214	621,114,566	12
							13

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 2 Column: g

182.3, 254, & 281

Schedule Page: 274 Line No.: 2 Column: i

182.3, 254, & 282

Schedule Page: 274 Line No.: 2 Column: k

Electric - Plant-Related:	Dec. 31, 2016	410.1 & Adjustments	Dec. 31, 2017
Electric Distribution Plant	\$790,931,323	\$23,577,454	\$814,508,777
Electric General Plant	84,491,876	625,428	85,117,304
Electric Intangible Plant	13,669,576	(5,132,619)	8,536,957
Electric Nuclear Fuel	58,027,039	841,685	58,868,724
Electric Nuclear Production Plant	606,973,785	503,540	607,477,325
Electric Production Plant	769,861,936	7,515,523	777,377,459
Electric Transmission Plant	750,452,003	56,702,545	807,154,548
Electric Transmission-Production Plant	20,369,343	(4,868,413)	15,500,930
Common (Allocation to Electric)	24,968,706	780,892	25,749,598
Regulatory Differences - Prior Flow Thru / Rate Change	(27,652,746)	(1,450,241,099)	(1,477,893,845)
Regulatory Differences - AFUDC Equity	199,968,096	(85,015,249)	114,952,847
Decommissioning Qualified	92,352,267	61,450,559	153,802,826
Total Electric - Plant-Related	\$3,384,413,204	(\$1,393,259,754)	\$1,991,153,450

Accumulated Deferred Income Taxes (Account No. 282). 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 related to regulatory differences related to income taxes.

Schedule Page: 274 Line No.: 3 Column: g

182.3, 254, & 282

Schedule Page: 274 Line No.: 3 Column: i

182.3 & 254

ACCUMULATED DEFERRED 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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric - Plant	39,190,177	12,774,634	
4	Electric - Non-Plant	135,790,403	92,142,751	193,278,186
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	174,980,580	104,917,385	193,278,186
10	Gas			
11	Gas	37,576,624	20,074,353	28,402,323
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	37,576,624	20,074,353	28,402,323
18	Non Operating	78,116		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	212,635,320	124,991,738	221,680,509
20	Classification of TOTAL			
21	Federal Income Tax	171,699,667	99,039,303	210,775,412
22	State Income Tax	40,935,653	25,952,435	10,905,097
23	Local Income Tax			

NOTES

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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		182.3	1,147,867		20,238	50,837,182	3
		254	6,697,939		133,993,300	161,950,329	4
							5
							6
							7
							8
			7,845,806		134,013,538	212,787,511	9
							10
		254	305,254		6,107,113	35,050,513	11
							12
							13
							14
							15
							16
			305,254		6,107,113	35,050,513	17
-815,886	233	219.1	36,567	219.1	43,564	-731,006	18
-815,886	233		8,187,627		140,164,215	247,107,018	19
							20
-816,050	233		7,441,231		127,544,879	179,250,923	21
164			746,396		12,619,336	67,856,095	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: i
182.3 & 283

Schedule Page: 276 Line No.: 3 Column: k

Electric - Plant-Related:	Dec. 31, 2016	410.1 & Adjustments	Dec. 31, 2017
Electric Distribution Plant	\$182,021	(\$5,009)	\$177,012
Electric General Plant	(5,516)	747,986	742,470
Electric Intangible Plant	5,705,592	27,645	5,733,237
Electric Nuclear Production Plant	4,483,442	(287,540)	4,195,902
Electric Production Plant	42,073	(7,821)	34,252
Electric Transmission Plant	56,988	(1,372)	55,616
Common (Allocation to Electric)	26,232,302	12,300,745	38,533,047
Regulatory Differences - AFUDC	2,493,275	(1,127,629)	1,365,646
Equity			
Total Electric - Plant-Related	\$39,190,177	\$11,647,005	\$50,837,182

Accumulated Deferred Income Taxes (Account No. 283). 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 related to regulatory differences related to income taxes. An adjustment is made to include the regulatory liability balance related to nonplant accumulated deferred income tax rate change.

Schedule Page: 276 Line No.: 4 Column: i
254 & 219.1

Schedule Page: 276 Line No.: 11 Column: i
254 & 219.1

Schedule Page: 276 Line No.: 19 Column: k

Refer to FERC page 278 for NSPM's regulatory liability related to nonplant excess ADIT.

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	ITC Gross-up to Pre-Tax Rate Levels	18,002,453	190	8,489,771		9,512,682
2						
3	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	29,252,510			1,430,947,773	1,460,200,283
4						
5						
6	Unrealized Gains on Decommissioning Trust	239,372,836			159,277,023	398,649,859
7						
8	Gain from Sales of Emission Allowances	52	411.8	52	59	59
9						
10	Electric Low Income Discount Program and PowerON Program	1,079,396	Various	13,532,969	12,453,573	
11						
12	- MN Electric E-002/GR-15-826					
13	- MN Electric E-002/M-04-1956					
14						
15	Gas Low Income Discount Program	64,711	Various	1,771,705	2,365,476	658,482
16	- MN Gas G-002/GR-06-1429					
17						
18	Pre-ARO Decommissioning	1,502,601,965	282	47,216,712	109,009,758	1,564,395,011
19						
20	Derivatives & Hedging - Retail Electric & Gas	15,320,788			1,835,860	17,156,648
21						
22	Minnesota Deferred Electric Commodity Costs	5,901,120	182.3	5,901,120		
23	- MN Docket E-002/M-14-364					
24						
25	South Dakota Deferred Electric Commodity Costs	1,932,476	456	54,077,698	53,274,160	1,128,938
26	- SD Docket EL-14-058					
27						
28	North Dakota Deferred Electric Commodity Costs	3,488,314	456	55,027,838	54,012,815	2,473,291
29	- ND Docket PU-12-813					
30						
31	Power Purchase Agreement	849,339	555	3,922	2,446	847,863
32						
33	South Dakota Transmission Cost Recovery Rider	815,664			236,401	1,052,065
34	- SD Docket EL16-031					
35						
36	Minnesota Gas State Energy Policy Rider	106,615	182.3	106,615		
37	- MN Docket G-002/M-16-206					
38						
39						
40						
41	TOTAL	1,868,456,818		261,366,317	1,971,666,695	3,578,757,196

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Department of Energy Settlement Payment	13,832,805	142	13,857,686	11,229,940	11,205,059
2	- MN Docket E-002/M-15-1089					
3	- MN Docket E-002/M-17-828					
4						
5	Minnesota Retail Asset Margin Sharing	4,748,464	557	22,890,562	22,305,515	4,163,417
6	- MN Docket E-002/GR-12-961					
7	North Dakota Retail Asset and Non-Asset	644,172	557	1,756,241	2,657,766	1,545,697
8	Margin Sharing					
9	- ND Docket PU-10-657					
10						
11	South Dakota Retail Asset and Non-Asset	252,463	557	1,507,201	2,275,184	1,020,446
12	Margin Sharing					
13	- SD Docket EL-12-046					
14						
15	South Dakota Production Tax Credit Sharing	1,677,535	557	6,519,317	6,214,326	1,372,544
16	- SD Docket EL-11-019					
17						
18	Minnesota Service Quality Program	571,500	142	639,050	730,775	663,225
19	- MN Docket E-002/M-16-281					
20	- MN Docket E-002/M-16-382					
21						
22	North Dakota Service Quality Program	199,875	Various	222,399	22,524	
23	- ND Docket PU-10-657					
24	- ND Docket PU-11-55					
25	- ND Docket PU-12-813					
26						
27	South Dakota Fuel Clause Adjustment Charge	(5,575)	431	17,392	22,967	
28	- SD EL-14-058					
29						
30	Transmission Formula Rates	13,751,728	Various	2,718,931	297,315	11,330,112
31						
32	North Dakota ITC	7,575,029	410.1	2,768,280	1,100,974	5,907,723
33						
34	South Dakota Infrastructure	494,974	407.4	10,727,235	11,261,700	1,029,439
35	- SD Docket EL-16-032					
36						
37	2016 Minnesota Revenue Decoupling	1,781,212	407.4	912,870		868,342
38	- MN Docket E-002/GR-13-868					
39	- MN Docket E-002/GR-15-826					
40						
41	TOTAL	1,868,456,818		261,366,317	1,971,666,695	3,578,757,196

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	North Dakota Renewable Energy Rider	353,061	407.4	1,461,679	1,990,497	881,879
2	- ND Docket PU-16-687					
3						
4	Minnesota Transmission Cost Recovery Rider	3,344,222	182.3	3,344,222		
5	- MN Docket E-002/GR-07-1156					
6	- MN Docket E-002/GR-15-891					
7						
8	Transco Administrative Services	213,617	407.4	53,404		160,213
9	Agreement					
10	- MN Docket E002/AI-14-759					
11	- MN Docket E002/AI-15-826					
12	- Amortized over three years (01/2016-12/2018)					
13						
14	Windsorce	233,497	Various	5,841,446	6,303,584	695,635
15	- MN Docket E-002/M-01-1479					
16	- MN Docket E-002/GR-13-868					
17						
18	2017 Minnesota Deferred Property Tax				5,561,793	5,561,793
19	- MN Docket E-002/GR-15-826					
20						
21	Conservation and Energy Management Program Costs				920,899	920,899
22	Minnesota Natural Gas					
23	- MN Docket G-002/M-17-258					
24	- Generally amortized over 12 month					
25	period following the expenditure					
26						
27	Minnesota Renewable Energy Standard				14,376,790	14,376,790
28	- MN Docket G-002/M-15-805					
29						
30	Nonplant Excess ADIT				55,904,209	55,904,209
31						
32	Renewable Development Fund Rider				5,074,593	5,074,593
33	- MN Docket E-002/M-16-811					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,868,456,818		261,366,317	1,971,666,695	3,578,757,196

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 10 Column: c

Accounts charged:	
142	\$13,156,889
232	376,080
Total	<u>\$13,532,969</u>

Schedule Page: 278 Line No.: 15 Column: c

Accounts charged:	
142	\$1,624,854
232	146,851
Total	<u>\$1,771,705</u>

Schedule Page: 278.1 Line No.: 22 Column: c

Accounts charged:	
142	\$22,349
456	200,050
Total	<u>\$222,399</u>

Schedule Page: 278.1 Line No.: 30 Column: c

Accounts charged:	
456.1	\$1,409,862
565	1,309,069
Total	<u>\$2,718,931</u>

Schedule Page: 278.2 Line No.: 14 Column: c

Accounts charged:	
555	\$5,618,377
921	223,069
Total	<u>\$5,841,446</u>

Schedule Page: 278.2 Line No.: 30 Column: f

Electric	\$56,084,754
Gas	2,761,781
Total	<u>\$58,846,535</u>
Reserve	(2,942,326)
	<u>\$55,904,209</u>

The total related to nonplant excess ADIT is \$58,846,535. This amount would be included as a decrease to rate base for the purpose of calculating the NSP companies formula rates, as applicable.

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	1,311,929,131	1,316,434,968
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,524,374,438	1,522,480,639
5	Large (or Ind.) (See Instr. 4)	690,162,808	686,231,582
6	(444) Public Street and Highway Lighting	25,538,287	26,402,371
7	(445) Other Sales to Public Authorities	9,609,774	9,176,485
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	657,561	654,722
10	TOTAL Sales to Ultimate Consumers	3,562,271,999	3,561,380,767
11	(447) Sales for Resale	95,341,471	83,071,627
12	TOTAL Sales of Electricity	3,657,613,470	3,644,452,394
13	(Less) (449.1) Provision for Rate Refunds	-22,224,485	20,595,351
14	TOTAL Revenues Net of Prov. for Refunds	3,679,837,955	3,623,857,043
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,200,682	5,975,478
17	(451) Miscellaneous Service Revenues	3,090,294	3,061,422
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	4,878,366	5,014,177
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	501,564,990	483,031,757
22	(456.1) Revenues from Transmission of Electricity of Others	234,505,456	255,278,682
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	750,239,788	752,361,516
27	TOTAL Electric Operating Revenues	4,430,077,743	4,376,218,559

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
9,899,976	10,107,329	1,302,327	1,291,114	2
				3
15,104,083	15,377,004	155,985	155,382	4
8,829,073	8,889,667	551	548	5
144,914	163,263	5,300	4,996	6
80,228	77,156	2,235	2,245	7
				8
7,393	7,500			9
34,065,667	34,621,919	1,466,398	1,454,285	10
6,654,822	6,897,102			11
40,720,489	41,519,021	1,466,398	1,454,285	12
				13
40,720,489	41,519,021	1,466,398	1,454,285	14

Line 12, column (b) includes \$ 14,049,547 of unbilled revenues.
 Line 12, column (d) includes -72,363 MWH relating to unbilled revenues

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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 twelve month average minimum registered demand of 1,000 kilowatts 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 twelve month average minimum registered demand of 1,000 kilowatts or more.

Schedule Page: 300 Line No.: 13 Column: b

Credit balance results from differences between final and interim rates in Minnesota electric rate case docket 15-826.

Schedule Page: 300 Line No.: 17 Column: b

Connection charges	\$ 2,694,380
NSF Check Fees	323,873
Other, less than \$250,000 each	72,041
	<u>\$ 3,090,294</u>

Schedule Page: 300 Line No.: 17 Column: c

Connection charges	\$ 2,738,661
NSF Check Fees	297,644
Other, less than \$250,000 each	25,117
	<u>\$ 3,061,422</u>

Schedule Page: 300 Line No.: 19 Column: b

Rent from Electric Property (Account No. 454). The rent revenue credit from electric property included in the formula is income directly related to transmission facilities, such as pole attachments, rentals and special use.

Schedule Page: 300 Line No.: 21 Column: b

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expenses	\$ 237,479,540
Variable Production Expenses	187,264,280
Transmission Expenses	65,477,314
Total Interchange Agreement	<u>\$ 490,221,134</u>

Also includes the following items:

Change in net over-recovered electric commodity costs	\$ 7,719,681
Fees charged to burn Refuse Derived Fuel	5,860,140
Windsor Program	5,841,446
Renewable*Connect	2,092,013
EI Mutual Aid Revenue	1,292,525
Work on Customers' Equipment	1,099,113
Distribution Facility Fixed Charges	721,632
Fuel Refund	560,038
Purchased Power Reimbursement	478,071
Facilities Agreement	473,763

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/06/2018	2017/Q4
FOOTNOTE DATA			

Manitoba Hydro Energy Service Agreement	300,000
Service Quality Plans	(530,740)
Net distribution of commodity trading margins under Joint Operating Agreement	(4,367,776)
Conservation Improvement Program incentive, net of accruals and recoveries	(10,563,326)
Other, less than \$250,000 each	367,276
	\$ 501,564,990

Schedule Page: 300 Line No.: 21 Column: c

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expenses	\$ 239,774,694
Variable Production Expenses	181,754,204
Transmission Expenses	54,005,161
Total Interchange Agreement	\$ 475,534,059

Also includes the following items:

Fees charged to burn Refuse Derived Fuel	\$ 7,010,071
Windsor Program	5,251,481
Energy Services Revenue	629,402
Project Bid Fees	475,000
Work on Customers' Equipment	420,752
Conservation Improvement Program incentive, net of accruals and recoveries	(917,313)
Net distribution of commodity trading margins under Joint Operating Agreement	(2,199,587)
Change in net over-recovered electric commodity costs	(3,529,219)
Other, less than \$250,000 each	357,111
	\$ 483,031,757

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					
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	TOTAL				

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	RESIDENTIAL					
2	Minnesota					
3	A00 Water Heating	176	21,749	41	4,293	0.1236
4	A01 Residential	4,749,309	651,929,044	752,931	6,308	0.1373
5	A02 Residential Time of Day	3,381	407,505	293	11,539	0.1205
6	A03 Residential Underground	3,596,912	481,949,836	383,542	9,378	0.1340
7	A04 Residential TOD Undergrnd	3,586	437,550	260	13,792	0.1220
8	A05 Energy Control	34,996	2,958,324	3,090	11,326	0.0845
9	A06 Limited Off Peak	2,701	218,753	380	7,108	0.0810
10	A07 Auto Protective Lighting	6,481	1,146,686			0.1769
11	A08 Residential Vehicle Tariff	542	49,292			0.0909
12	Unbilled	15,157	3,584,253			0.2365
13	North Dakota					
14	D01 Residential	583,664	62,786,075	68,118	8,568	0.1076
15	D02 Residential Time of Day	709	63,755	27	26,259	0.0899
16	D03 Residential Underground	159,349	16,049,408	12,243	13,016	0.1007
17	D04 Residential TOD Undergrnd	85	7,693	4	21,250	0.0905
18	D05 Energy Control	3,794	277,766	298	12,732	0.0732
19	D10 Limited Off Peak	785	51,195	109	7,202	0.0652
20	D11 Auto Protective Lighting	339	55,966			0.1651
21	Unbilled	4,608	379,746			0.0824
22	South Dakota					
23	E01 Residential	321,497	39,648,222	44,313	7,255	0.1233
24	E02 Residential Time of Day	31	3,287	3	10,333	0.1060
25	E03 Residential Underground	405,816	48,842,477	36,466	11,129	0.1204
26	E04 Residential Time of Day	45	5,123	3	15,000	0.1138
27	E06 Residential Heat Pump	1,605	139,260	102	15,735	0.0868
28	E10 Energy Control	1,222	91,515	103	11,864	0.0749
29	E11 Limited Off Peak	12	775	1	12,000	0.0646
30	E12 Auto Protective Lighting	350	65,112			0.1860
31	Unbilled	2,824	758,764			0.2687
32	Total Residential	9,899,976	1,311,929,131	1,302,327	7,602	0.1325
33						
34	COMMERCIAL AND INDUSTRIAL					
35	Minnesota					
36	A05 Energy Control	1,729	141,470	100	17,290	0.0818
37	A06 Limited Off Peak	1,806	163,779	83	21,759	0.0907
38	A07 Auto Protective Lighting	24,477	3,606,517			0.1473
39	A09 Small General Service	24	12,968	99	242	0.5403
40	A10 Small General Service	775,136	99,639,313	73,938	10,484	0.1285
41	TOTAL Billed	33,995,872	3,550,600,755	1,466,398	23,183	0.1044
42	Total Unbilled Rev.(See Instr. 6)	69,795	11,671,244	0	0	0.1672
43	TOTAL	34,065,667	3,562,271,999	1,466,398	23,231	0.1046

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	A11 Water Heating	236	27,730	81	2,914	0.1175
2	A12 Small General TOD Service	40,355	4,487,229	2,861	14,105	0.1112
3	A13 Direct Current	3	10,893	3	1,000	3.6310
4	A14 General Service	7,993,447	839,459,622	40,776	196,033	0.1050
5	A15 General TOD Service	8,147,617	668,988,760	4,470	1,822,733	0.0821
6	A16 Small General kWh metered	14,297	1,869,116	2,960	4,830	0.1307
7	A18 Small General TOD Service	27,974	3,355,881	4,345	6,438	0.1200
8	A22 Small Gen TOD Low Watt	2,353	310,851	735	3,201	0.1321
9	A23 Peak Control Tiered	1,125,964	113,110,875	1,436	784,097	0.1005
10	A24 Peak Control Time of Day	2,494,214	193,746,876	346	7,208,711	0.0777
11	A27 Tier 1 Energy Control	402,326	25,010,144	14	28,737,571	0.0622
12	A29 Hiawatha Light Rail	24,154	2,257,013	16	1,509,625	0.0934
13	A63 Experimental Real Time	20,227	1,392,413	2	10,113,500	0.0688
14	Unbilled	45,570	6,101,675			0.1339
15	North Dakota					
16	D05 Energy Control	1,398	102,460	52	26,885	0.0733
17	D10 Limited Off Peak	518	41,432	34	15,235	0.0800
18	D11 Auto Protective Lighting	2,708	351,225			0.1297
19	D12 Small General Service	103,108	11,179,599	8,170	12,620	0.1084
20	D14 Small General TOD Service	2,218	230,908	214	10,364	0.1041
21	D16 General Service	710,853	68,187,241	3,623	196,206	0.0959
22	D17 General TOD Service	202,954	16,334,853	203	999,773	0.0805
23	D18 Small General TOD Service	558	64,367	101	5,525	0.1154
24	D19 Small General kWh metered	953	125,204	227	4,198	0.1314
25	D20 Peak Control	33,867	3,130,905	51	664,059	0.0924
26	D21 Peak Control Time of Day	132,628	9,529,164	13	10,202,154	0.0718
27	D22 Tier 1 Energy Control	233,246	16,206,829	69	3,380,377	0.0695
28	D34 Sm General TOD Low Watt	68	8,146	21	3,238	0.1198
29	Unbilled	1,497	120,074			0.0802
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	33,995,872	3,550,600,755	1,466,398	23,183	0.1044
42	Total Unbilled Rev.(See Instr. 6)	69,795	11,671,244	0	0	0.1672
43	TOTAL	34,065,667	3,562,271,999	1,466,398	23,231	0.1046

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						
2	South Dakota					
3	E10 Energy Control	129	9,688	9	14,333	0.0751
4	E11 Limited Off Peak	325	23,618	8	40,625	0.0727
5	E12 Auto Protective Lighting	2,303	370,631			0.1609
6	E13 Small General Service	84,958	9,690,419	7,231	11,749	0.1141
7	E14 Small General TOD Service	2,152	254,174	356	6,045	0.1181
8	E15 General Service	657,151	64,507,733	3,495	188,026	0.0982
9	E16 General TOD Service	476,669	37,413,651	221	2,156,873	0.0785
10	E18 Small General TOD Service	59	8,001	66	894	0.1356
11	E20 Peak Control	60,149	6,035,217	76	791,434	0.1003
12	21 Peak Control Time of Day	50,691	3,753,953	14	3,620,786	0.0741
13	E22 Energy Control	27,232	2,036,475	17	1,601,882	0.0748
14	Unbilled	2,855	1,128,154			0.3952
15	Total Commercial and Industrial	23,933,156	2,214,537,246	156,536	152,892	0.0925
16						
17	PUBLIC STREET AND HIGHWAY					
18	Minnesota					
19	A30 Street Light Co Owned	53,538	17,576,019	1,732	30,911	0.3283
20	A32 Street Light Cust Owned	31,636	2,354,159	428	73,916	0.0744
21	A34 Street Lighting Metered	33,890	2,488,827	2,498	13,567	0.0734
22	A37 Street Lighting St Paul	1,004	149,164	1	1,004,000	0.1486
23	Unbilled	-3,081	-455,780			0.1479
24	North Dakota					
25	D30 Street Light Co Owned	942	561,778	62	15,194	0.5964
26	D31 Street Light Cust Owned	11,725	928,216	33	355,303	0.0792
27	D32 Street Lighting Ornamental	37	3,615	2	18,500	0.0977
28	D33 Street Lighting Metered	1,873	122,671	96	19,510	0.0655
29	Unbilled	21	2,044			0.0973
30	South Dakota					
31	E30 Street Light Co Owned	1,456	768,138	99	14,707	0.5276
32	E31 Street Light Cust Owned	3,341	308,497	16	208,813	0.0923
33	E32 Street Lighting Metered	7,355	621,193	233	31,567	0.0845
34	E33 Street Lighting Ornamental	1,234	105,707	100	12,340	0.0857
35	Unbilled	-57	4,039			-0.0709
36	Total Public Street and Highway	144,914	25,538,287	5,300	27,342	0.1762
37						
38						
39						
40						
41	TOTAL Billed	33,995,872	3,550,600,755	1,466,398	23,183	0.1044
42	Total Unbilled Rev.(See Instr. 6)	69,795	11,671,244	0	0	0.1672
43	TOTAL	34,065,667	3,562,271,999	1,466,398	23,231	0.1046

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						
2	OTHER SALES TO PUBLIC					
3	Minnesota					
4	A40 Small Municipal Pumping	7,225	968,446	960	7,526	0.1340
5	A41 Municipal Pumping	59,716	7,211,811	564	105,879	0.1208
6	A42 Fire Siren		36,776	525		
7	Unbilled	306	39,628			0.1295
8	North Dakota					
9	D40 Small Municipal Pumping	936	102,849	79	11,848	0.1099
10	D41 Municipal Pumping	11,951	1,237,658	84	142,274	0.1036
11	D42 Fire Siren		1,005	23		
12	Unbilled	94	8,648			0.0920
13	South Dakota					
14	E40 Fire Siren		2,953			
15	Total Other Sales to Public Autho	80,228	9,609,774	2,235	35,896	0.1198
16						
17	Interdepartmental Sales	7,393	657,561			0.0889
18	Total Interdepartmental	7,393	657,561			0.0889
19						
20	Footnote for Instruction 5:					
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	33,995,872	3,550,600,755	1,466,398	23,183	0.1044
42	Total Unbilled Rev.(See Instr. 6)	69,795	11,671,244	0	0	0.1672
43	TOTAL	34,065,667	3,562,271,999	1,466,398	23,231	0.1046

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 304.3 Line No.: 20 Column: a

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	\$ 4,447
A01	117,799,750
A02	79,348
A03	89,896,677
A04	84,573
A05	919,051
A06	114,113
A07	578,232
A08	12,795
A09	636
A10	20,020,523
A11	6,135
A12	1,045,325
A13	85
A14	198,353,589
A15	197,935,495
A16	370,349
A18	725,473
A22	61,041
A23	27,918,219
A24	60,322,269
A27	9,653,466
A29	597,883
A30	997,046
A32	589,454
A34	630,556
A37	18,677
A40	187,458
A41	1,489,717
A52	14,723
A55	639
A63	482,615
Minnesota jurisdiction	<u>\$730,910,359</u>

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

D01	\$ 13,853,474
D02	16,822
D03	3,781,842
D04	2,012
D05	124,859
D10	31,195
D11	53,239
D12	2,531,737
D14	54,686
D16	17,228,328
D17	4,741,545
D18	13,705
D19	23,393
D20	809,686
D21	3,046,781
D22	5,482,167
D30	16,471

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/06/2018	2017/Q4
FOOTNOTE DATA			

D31	205,070
D32	639
D33	32,758
D34	1,663
D40	22,986
D41	289,745
North Dakota jurisdiction	<u>\$ 52,364,803</u>

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

E01	\$ 6,972,249
E02	733
E03	8,791,874
E04	985
E06	35,015
E10	29,649
E11	7,365
E12	43,711
E13	1,850,271
E14	46,528
E15	14,061,440
E16	9,921,374
E18	1,273
E20	1,288,103
E21	1,063,666
E22	569,826
E30	23,369
E31	54,255
E32	119,638
E33	20,169
South Dakota jurisdiction	<u>\$ 44,901,493</u>
Total Company	<u>\$828,176,655</u>

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 not 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 long-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 Classification (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	NSP-Wisconsin	RQ		N/A	N/A	N/A
2	Basin Electric Power Cooperative	OS	V6	N/A	N/A	N/A
3	City of Ada, MN	OS	V6	N/A	N/A	N/A
4	City of Ada, MN	SF	V6	N/A	N/A	N/A
5	City of Kasota, MN	OS	V6	N/A	N/A	N/A
6	City of Kasota, MN	SF	V6	N/A	N/A	N/A
7	Dahlberg Light and Power Co.	OS	V6	N/A	N/A	N/A
8	Dahlberg Light and Power Co.	SF	V6	N/A	N/A	N/A
9	Great River Energy	OS	V6	N/A	N/A	N/A
10	Luminant Energy Company LLC	OS	V6	N/A	N/A	N/A
11	Manitoba Hydro-Electric Board	OS	V6	N/A	N/A	N/A
12	Midwest Independent System Operator	OS	V6	N/A	N/A	N/A
13	Minnesota Municipal Power Agency	OS	V6	N/A	N/A	N/A
14	Natural Gas Exchange Inc.	OS	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
5,928,421		357,967,434		357,967,434	1
	750,000			750,000	2
	49,500			49,500	3
5,467		477,547		477,547	4
	31,000			31,000	5
3,971		239,980		239,980	6
4,161	186,315	80,338		266,653	7
112,570		5,550,232		5,550,232	8
	330,000			330,000	9
16,000			642,843	642,843	10
	62,500			62,500	11
6,240,632	375,279	74,310,893	2,862,837	77,549,009	12
	60,000			60,000	13
50,400			2,316,302	2,316,302	14
5,928,421	0	357,967,434	0	357,967,434	
6,654,822	2,173,629	86,903,567	6,264,275	95,341,471	
12,583,243	2,173,629	444,871,001	6,264,275	453,308,905	

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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
17,600			442,293	442,293	1
14,617	52,770	249,042		301,812	2
12,824		484,016		484,016	3
51,140	276,265	883,919		1,160,184	4
125,440		4,627,600		4,627,600	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
5,928,421	0	357,967,434	0	357,967,434	
6,654,822	2,173,629	86,903,567	6,264,275	95,341,471	
12,583,243	2,173,629	444,871,001	6,264,275	453,308,905	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 1 Column: a

Ownership interest or affiliation per Instruction 2:

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc.

Schedule Page: 310 Line No.: 2 Column: c

V6 - FERC Electric Tariff, First Revised Volume No. 6

Schedule Page: 310 Line No.: 10 Column: j

Financial Trading

Schedule Page: 310 Line No.: 12 Column: j

Demand - Resource Adequacy Auction, Other - Ancillary services

Schedule Page: 310 Line No.: 14 Column: j

Financial Trading

Schedule Page: 310.1 Line No.: 1 Column: j

Financial Trading

Schedule Page: 310.1 Line No.: 12 Column: a

Total revenue and volumes sold will not match pages 300-1, line 11, due to differences in accounting classification associated with the Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) Interchange Agreement.

	Revenue	Mwh
page 300, line 11(b)	\$95,341,471	6,654,822
page 311 total (k)	\$453,308,905	12,583,243
less net interchange agreement	<u>(357,967,434)</u>	<u>(5,928,421)</u>
	\$95,341,471	6,654,822

Schedule Page: 310.1 Line No.: 13 Column: a

Sales for Resale (Account No. 447). The revenue credit from sales for resale included in the formula are for bundled sales that are not included in the formula divisor.

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	3,676,860	4,002,410
5	(501) Fuel	318,564,855	292,786,848
6	(502) Steam Expenses	24,340,610	20,140,543
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,040,486	4,742,224
10	(506) Miscellaneous Steam Power Expenses	13,924,056	18,418,746
11	(507) Rents	3,259,384	3,700,748
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	367,806,251	343,791,519
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,957,690	2,720,065
16	(511) Maintenance of Structures	5,369,444	7,163,883
17	(512) Maintenance of Boiler Plant	23,979,849	32,136,719
18	(513) Maintenance of Electric Plant	7,377,092	10,288,687
19	(514) Maintenance of Miscellaneous Steam Plant	11,965,103	15,501,525
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	51,649,178	67,810,879
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	419,455,429	411,602,398
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	65,468,746	71,715,041
25	(518) Fuel	114,361,824	116,981,547
26	(519) Coolants and Water	9,165,290	8,674,239
27	(520) Steam Expenses	50,048,519	47,803,622
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,521,413	4,147,206
31	(524) Miscellaneous Nuclear Power Expenses	131,053,296	138,059,327
32	(525) Rents	11,718,071	10,763,466
33	TOTAL Operation (Enter Total of lines 24 thru 32)	384,337,159	398,144,448
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	5,229,084	6,647,149
36	(529) Maintenance of Structures	419,818	845,272
37	(530) Maintenance of Reactor Plant Equipment	39,119,015	42,572,905
38	(531) Maintenance of Electric Plant	11,596,004	17,491,413
39	(532) Maintenance of Miscellaneous Nuclear Plant	31,371,710	30,900,109
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	87,735,631	98,456,848
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	472,072,790	496,601,296
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	18,122	2,201
45	(536) Water for Power		663
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	425,694	206,041
48	(539) Miscellaneous Hydraulic Power Generation Expenses	121,102	147,274
49	(540) Rents	41,316	23,244
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	606,234	379,423
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	14,841	25,154
54	(542) Maintenance of Structures	81,785	86,278
55	(543) Maintenance of Reservoirs, Dams, and Waterways	30,160	45,098
56	(544) Maintenance of Electric Plant	308,887	31,618
57	(545) Maintenance of Miscellaneous Hydraulic Plant	418	7,970
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	436,091	196,118
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,042,325	575,541

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	1,456,943	944,062
63	(547) Fuel	134,988,213	145,528,076
64	(548) Generation Expenses	6,888,806	11,534,509
65	(549) Miscellaneous Other Power Generation Expenses	18,006,000	6,893,868
66	(550) Rents	2,655,703	1,446,954
67	TOTAL Operation (Enter Total of lines 62 thru 66)	163,995,665	166,347,469
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,141,460	476,689
70	(552) Maintenance of Structures	6,722,810	4,401,881
71	(553) Maintenance of Generating and Electric Plant	10,371,752	9,802,663
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,489,712	6,700,326
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	20,725,734	21,381,559
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	184,721,399	187,729,028
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	705,284,433	670,501,522
77	(556) System Control and Load Dispatching	1,348,426	1,198,665
78	(557) Other Expenses	63,768,822	73,921,202
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	770,401,681	745,621,389
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,847,693,624	1,842,129,652
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	12,049,937	11,141,883
84			
85	(561.1) Load Dispatch-Reliability	2,548	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,468,695	5,980,333
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,411,149	7,057,099
89	(561.5) Reliability, Planning and Standards Development	5,299	8,451
90	(561.6) Transmission Service Studies	-37	-5,280
91	(561.7) Generation Interconnection Studies	-3,190	10,641
92	(561.8) Reliability, Planning and Standards Development Services	2,830,128	2,930,972
93	(562) Station Expenses	1,242,591	1,568,807
94	(563) Overhead Lines Expenses	1,242,924	1,263,292
95	(564) Underground Lines Expenses	5,763	
96	(565) Transmission of Electricity by Others	206,928,323	193,894,526
97	(566) Miscellaneous Transmission Expenses	116,450,515	112,069,854
98	(567) Rents	3,498,285	2,879,927
99	TOTAL Operation (Enter Total of lines 83 thru 98)	356,132,930	338,800,505
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	118,220	180,957
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	4,916,167	7,526,675
108	(571) Maintenance of Overhead Lines	8,110,161	8,923,868
109	(572) Maintenance of Underground Lines	22,321	289,207
110	(573) Maintenance of Miscellaneous Transmission Plant	39,528	30,414
111	TOTAL Maintenance (Total of lines 101 thru 110)	13,206,397	16,951,121
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	369,339,327	355,751,626

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	250,256	184,996
116	(575.2) Day-Ahead and Real-Time Market Facilitation	106,626	112,413
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	12,234	59,896
120	(575.6) Market Monitoring and Compliance	12,811	14,905
121	(575.7) Market Facilitation, Monitoring and Compliance Services	9,810,597	9,204,811
122	(575.8) Rents		6,269
123	Total Operation (Lines 115 thru 122)	10,192,524	9,583,290
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 Exps (Total 123 and 130)	10,192,524	9,583,290
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	11,150,217	9,779,861
135	(581) Load Dispatching	256,427	3,333,688
136	(582) Station Expenses	4,528,926	3,461,795
137	(583) Overhead Line Expenses	2,522,941	2,322,654
138	(584) Underground Line Expenses	7,021,215	7,511,589
139	(585) Street Lighting and Signal System Expenses	1,208,765	1,087,263
140	(586) Meter Expenses	942,016	1,453,214
141	(587) Customer Installations Expenses	3,136,375	3,717,411
142	(588) Miscellaneous Expenses	14,047,616	12,289,770
143	(589) Rents	4,300,647	4,030,969
144	TOTAL Operation (Enter Total of lines 134 thru 143)	49,115,145	48,988,214
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	95,015	367,998
147	(591) Maintenance of Structures	2,519	238
148	(592) Maintenance of Station Equipment	8,227,071	9,177,185
149	(593) Maintenance of Overhead Lines	41,521,691	38,163,776
150	(594) Maintenance of Underground Lines	7,085,172	10,162,873
151	(595) Maintenance of Line Transformers	2,288,415	2,364,795
152	(596) Maintenance of Street Lighting and Signal Systems	1,439,756	1,626,677
153	(597) Maintenance of Meters	102,106	109,271
154	(598) Maintenance of Miscellaneous Distribution Plant	1,288,711	8,179
155	TOTAL Maintenance (Total of lines 146 thru 154)	62,050,456	61,980,992
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	111,165,601	110,969,206
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	108,716	118,011
160	(902) Meter Reading Expenses	19,773,721	19,520,967
161	(903) Customer Records and Collection Expenses	22,506,351	23,841,892
162	(904) Uncollectible Accounts	13,011,947	12,514,661
163	(905) Miscellaneous Customer Accounts Expenses	-81	621
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,400,654	55,996,152

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	104,765,143	88,612,847
169	(909) Informational and Instructional Expenses	1,778,286	1,322,748
170	(910) Miscellaneous Customer Service and Informational Expenses	133,259	
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	106,676,688	89,935,595
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,808	1,482
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	4,808	1,482
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	85,857,392	72,782,921
182	(921) Office Supplies and Expenses	60,480,276	56,649,158
183	(Less) (922) Administrative Expenses Transferred-Credit	47,462,273	41,946,226
184	(923) Outside Services Employed	30,014,840	28,050,158
185	(924) Property Insurance	2,706,000	7,358,647
186	(925) Injuries and Damages	11,399,976	11,951,414
187	(926) Employee Pensions and Benefits	83,620,476	88,142,330
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	6,940,705	7,748,595
190	(929) (Less) Duplicate Charges-Cr.	5,576,918	4,899,638
191	(930.1) General Advertising Expenses	3,085,801	3,077,317
192	(930.2) Miscellaneous General Expenses	3,451,951	3,315,655
193	(931) Rents	34,251,854	31,089,269
194	TOTAL Operation (Enter Total of lines 181 thru 193)	268,770,080	263,319,600
195	Maintenance		
196	(935) Maintenance of General Plant	1,219,769	2,212,100
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	269,989,849	265,531,700
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,770,463,075	2,729,898,703

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 64 Column: b

Account No. 548 Generation Expenses	\$ 6,888,806
Account No. 548.1 Operation of Energy Storage Equipment	0
	<u>\$ 6,888,806</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 64 Column: c

Account No. 548 Generation Expenses	\$ 11,525,485
Account No. 548.1 Operation of Energy Storage Equipment	9,024
	<u>\$ 11,534,509</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: b

Account No. 553 Maintenance of Generating and Electric Plant	\$ 10,371,752
Account No. 553.1 Maintenance of Energy Storage Equipment	0
	<u>\$ 10,371,752</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: c

Account No. 553 Maintenance of Generating and Electric Plant	\$ 9,724,606
Account No. 553.1 Maintenance of Energy Storage Equipment	78,057
	<u>\$ 9,802,663</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: b

Account No. 555 Purchased Power	\$705,308,410
Account No. 555.1 Power Purchased for Storage Operations	(23,977)
	<u>\$705,284,433</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: c

Account No. 555 Purchased Power	\$670,498,313
Account No. 555.1 Power Purchased for Storage Operations	3,209
	<u>\$670,501,522</u>

See Note 15 to the Financial Statements

Schedule Page: 320 Line No.: 78 Column: b

Includes \$48,769,506 of fixed costs and \$18,006,880 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 78 Column: c

Includes \$46,601,900 of fixed costs and \$16,415,715 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 90 Column: b

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing transmission service studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.6.

Schedule Page: 320 Line No.: 90 Column: c

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing transmission service studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.6.

Schedule Page: 320 Line No.: 91 Column: b

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 97 Column: b

Includes \$110,457,340 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 97 Column: c

Includes \$107,465,543 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 112 Column: b

Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the FERC-approved Interchange Agreement.

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)	Average Monthly CP Demand (f)
1	Adams Wind Generations, LLC	LU		N/A	N/A	N/A
2	Agassiz Beach LLC	LU		N/A	N/A	N/A
3	Aurora Distributed Solar, LLC	AD		N/A	N/A	N/A
4	Aurora Distributed Solar, LLC	LU		N/A	N/A	N/A
5	Benson Power, LLC	LU		N/A	N/A	N/A
6	Best Power International LLC	LU		N/A	N/A	N/A
7	Big Blue	LU		N/A	N/A	N/A
8	Bisson Windfarm, L.L.C.	AD		N/A	N/A	N/A
9	Bisson Windfarm, L.L.C.	LU		N/A	N/A	N/A
10	Boeve Windfarm, L.L.C.	LU		N/A	N/A	N/A
11	Byllesby	LU		2	N/A	N/A
12	Cannon Falls Energy Center	LU		346	N/A	N/A
13	Carleton College	LU		N/A	N/A	N/A
14	CG Windfarm, L.L.C.	AD		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	Lake Benton Power Partners, L.L.C.	LU		N/A	N/A	N/A
2	Laurentian Energy Authority, L.L.C.	LU		N/A	N/A	N/A
3	LCO Hydro	LU		N/A	N/A	N/A
4	Lincoln Heights Wind Holdings	LU		N/A	N/A	N/A
5	LSP Cottage Grove Incorporated	AD		N/A	N/A	N/A
6	LSP Cottage Grove Incorporated	LU		245	N/A	N/A
7	Manitoba Hydro	LU		365	N/A	N/A
8	Mankato Energy Center, L.L.C.	AD		N/A	N/A	N/A
9	Mankato Energy Center, L.L.C.	LU		375	N/A	N/A
10	Marshall Solar	LU		N/A	N/A	N/A
11	Metro Wind LLC	LU		N/A	N/A	N/A
12	Midcontinental ISO	AD		N/A	N/A	N/A
13	Midcontinental ISO	SF		N/A	N/A	N/A
14	MinnDakota	LU		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	Miscellaneous	OS		N/A	N/A	N/A
2	Moraine Wind, L.L.C.	LU		N/A	N/A	N/A
3	NAE Lakota Ridge, LLC	AD		N/A	N/A	N/A
4	NAE Lakota Ridge, LLC	LU		N/A	N/A	N/A
5	NAE Shaokatan, LLC	LU		N/A	N/A	N/A
6	NAE Shaokatan Hills, LLC	AD		N/A	N/A	N/A
7	NAE Shaokatan Hills, LLC	LU		N/A	N/A	N/A
8	Natural Gas Exchange Inc.	OS		N/A	N/A	N/A
9	Neshkoro (Neshonoc)	LU		.4	N/A	N/A
10	New England ISO	OS		N/A	N/A	N/A
11	New Ulm	OS		N/A	N/A	N/A
12	New York ISO	OS		N/A	N/A	N/A
13	North Community Turbines LLC	LU		N/A	N/A	N/A
14	North Star Solar	LU		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	North Wind Turbines LLC	LU		N/A	N/A	N/A
2	NSP-M Solar Gardens	LU		N/A	N/A	N/A
3	Odell Wind Farm, LLC	LU		N/A	N/A	N/A
4	Olsen Windfarms	LU		N/A	N/A	N/A
5	Pine Bend	LU		N/A	N/A	N/A
6	Pipestone	LU		N/A	N/A	N/A
7	PJM Interconnection LLC	AD		N/A	N/A	N/A
8	PJM Interconnection LLC	OS		N/A	N/A	N/A
9	Prairie Rose Wind LLC	AD		N/A	N/A	N/A
10	Prairie Rose Wind LLC	LU		N/A	N/A	N/A
11	Rapidan Hydroelectric Facility	LU		2	N/A	N/A
12	Ridgewind Power Partners, LLC	AD		N/A	N/A	N/A
13	Ridgewind Power Partners, LLC	LU		N/A	N/A	N/A
14	Rock County Energy	LU		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	Rock Ridge Power Partners LLC	LU		N/A	N/A	N/A
2	Ruthton Ridge LLC	LU		N/A	N/A	N/A
3	SAF Hydroelectric, L.L.C.	LU		N/A	N/A	N/A
4	Shane's Wind Machine LLC	LU		N/A	N/A	N/A
5	Shell Energy North America US LP	OS		N/A	N/A	N/A
6	Slayton Solar, LLC	LU		N/A	N/A	N/A
7	South Ridge	LU		N/A	N/A	N/A
8	Southern Minnesota Municipal Power Agy	OS		N/A	N/A	N/A
9	Southwest Power Pool Electric Energy	AD		N/A	N/A	N/A
10	Southwest Power Pool Electric Energy	OS		N/A	N/A	N/A
11	St Cloud	AD		N/A	N/A	N/A
12	St Cloud	LU		7	N/A	N/A
13	St. Olaf College	AD		N/A	N/A	N/A
14	St. Olaf College	LU		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	St. Paul Cogeneration	LU		N/A	N/A	N/A
2	TG Windfarm, L.L.C.	AD		N/A	N/A	N/A
3	TG Windfarm, L.L.C.	LU		N/A	N/A	N/A
4	Tholen	LU		N/A	N/A	N/A
5	Tofteland Windfarm, L.L.C.	AD		N/A	N/A	N/A
6	Tofteland Windfarm, L.L.C.	LU		N/A	N/A	N/A
7	Twin Eagle Resource Management, LLC	OS		N/A	N/A	N/A
8	Uilk Wind Farm, LLC	LU		N/A	N/A	N/A
9	University of Minnesota	LU		N/A	N/A	N/A
10	Valley View Transmission	LU		N/A	N/A	N/A
11	Velva Windfarm, LLC	LU		N/A	N/A	N/A
12	Viking Wind Partners	LU		N/A	N/A	N/A
13	Western Area Power Administration	LU	NAEMA, WSPP	N/A	N/A	N/A
14	Westridge Windfarm, L.L.C.	AD		N/A	N/A	N/A
	Total					

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)	Average Monthly CP Demand (f)
1	Westridge Windfarm, L.L.C.	LU		N/A	N/A	N/A
2	Windcurrent Farms, L.L.C.	LU		N/A	N/A	N/A
3	Windvest	LU		N/A	N/A	N/A
4	Winona County Wind LLC	AD		N/A	N/A	N/A
5	Winona County Wind LLC	LU		N/A	N/A	N/A
6	WM Renewable Energy, LLC	LU		N/A	N/A	N/A
7	Woodstock Hills, L.L.C.	LU		N/A	N/A	N/A
8	Woodstock Municipal Wind, LLC	AD		N/A	N/A	N/A
9	Woodstock Municipal Wind, LLC	LU		N/A	N/A	N/A
10	Zephyr Wind	AD		N/A	N/A	N/A
11	Zephyr Wind	LU		N/A	N/A	N/A
12						
13						
14						
	Total					

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 monthly (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)	
49,222				3,396,181		3,396,181	1
4,815				105,448		105,448	2
1				48		48	3
135,665				12,009,224		12,009,224	4
405,982				69,008,004		69,008,004	5
1,924				171,432		171,432	6
126,812				6,464,131		6,464,131	7
-8				-265		-265	8
2,719				92,480		92,480	9
6,519				218,371		218,371	10
14,979			422,847	306,823		729,670	11
43,375			27,122,399	3,031,946		30,154,345	12
4,261				140,571		140,571	13
1				-264		-264	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
1,629				55,367		55,367	1
229,216				6,093,779		6,093,779	2
26,682				1,304,750		1,304,750	3
6,400					269,896	269,896	4
211,180			8,147,523	4,859,990		13,007,513	5
17,200				299,968		299,968	6
45,024				3,079,467		3,079,467	7
303				18,853		18,853	8
26,187				864,208		864,208	9
					-1	-1	10
					-67,056	-67,056	11
11,200					465,117	465,117	12
67,751				2,981,044		2,981,044	13
				-54,050		-54,050	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
692,216				31,962,547		31,962,547	1
5,958				208,483		208,483	2
287,818				12,701,038		12,701,038	3
82,582				2,713,932		2,713,932	4
58,923				4,083,199		4,083,199	5
18,267			439,310	338,299		777,609	6
3,795				197,220		197,220	7
				-11,450		-11,450	8
163,336				5,978,057		5,978,057	9
4,313				144,445		144,445	10
3,632				137,234		137,234	11
6,554				219,534		219,534	12
99,257				8,200,375		8,200,375	13
				13,980		13,980	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
506,055				14,145,767		14,145,767	1
263,194				32,108,854		32,108,854	2
15,373				198,510		198,510	3
23,046				760,406		760,406	4
				6,792		6,792	5
245,805			39,029,449	7,461,968		46,491,417	6
1,669,927			34,455,723	96,743,083		131,198,806	7
33,600				66,686		66,686	8
695,140			35,566,551	23,670,769		59,237,320	9
111,804				6,600,514		6,600,514	10
848				18,562		18,562	11
-146,617				-5,935,561		-5,935,561	12
2,676,516				24,195,137		24,195,137	13
531,455				20,836,984		20,836,984	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
25,642					421,926	421,926	1
323,706				14,738,875		14,738,875	2
28,929				1,362,967		1,362,967	3
23,581				1,105,950		1,105,950	4
31,667				692,823		692,823	5
36,727				1,730,320		1,730,320	6
34,478				1,614,884		1,614,884	7
					525,403	525,403	8
1,712			73,430	33,163		106,593	9
					14,583	14,583	10
			405,000			405,000	11
					-71,779	-71,779	12
48,597				3,207,343		3,207,343	13
187,156				11,785,905		11,785,905	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
48,778				3,219,319		3,219,319	1
153,281				17,071,475		17,071,475	2
807,349				18,169,557		18,169,557	3
1,932				72,512		72,512	4
27,557				1,375,212		1,375,212	5
25,513				841,825		841,825	6
					-242,949	-242,949	7
					-39,547	-39,547	8
				-11,098		-11,098	9
677,355				25,123,003		25,123,003	10
17,007			354,530	310,319		664,849	11
				12,132		12,132	12
85,919				5,678,992		5,678,992	13
25,493				841,327		841,327	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
5,081				167,684		167,684	1
48,975				1,072,346		1,072,346	2
41,688				2,071,083		2,071,083	3
7,096				234,133		234,133	4
34,400					1,657,324	1,657,324	5
2,563				292,129		292,129	6
5,560				183,523		183,523	7
				-1,432,255		-1,432,255	8
-235				-1,391		-1,391	9
4,484				79,914		79,914	10
			-222,439	524,404		301,965	11
56,667			1,465,735	1,333,268		2,799,003	12
7				215		215	13
23				743		743	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
147,707				21,952,165		21,952,165	1
				1		1	2
1,243				42,235		42,235	3
43,642				1,440,216		1,440,216	4
				1		1	5
2,174				73,873		73,873	6
14,400					354,588	354,588	7
13,374				917,654		917,654	8
18,320				323,989		323,989	9
31,692				2,042,996		2,042,996	10
31,850				1,051,092		1,051,092	11
33,566				1,107,574		1,107,574	12
11,787				332,955		332,955	13
				1		1	14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

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 monthly (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)	
1,757				59,749		59,749	1
4,846				169,610		169,610	2
5,493				181,288		181,288	3
				8		8	4
112				7,490		7,490	5
37,508				1,687,872		1,687,872	6
12,928				557,718		557,718	7
				19		19	8
2,474				167,794		167,794	9
				546		546	10
117,291				6,904,553		6,904,553	11
							12
							13
							14
12,842,688			147,260,058	554,736,870	3,287,505	705,284,433	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 3 Column: k
Prior period adjustment

Schedule Page: 326 Line No.: 5 Column: k
Formerly FibroMinn

Schedule Page: 326 Line No.: 8 Column: k
Housepower

Schedule Page: 326 Line No.: 14 Column: k
Housepower

Schedule Page: 326.1 Line No.: 4 Column: l
Financial trading

Schedule Page: 326.1 Line No.: 10 Column: l
Prior period adjustment

Schedule Page: 326.1 Line No.: 11 Column: l
Compensation for non-renewable energy rebate

Schedule Page: 326.1 Line No.: 12 Column: l
Financial trading

Schedule Page: 326.1 Line No.: 14 Column: k
Prior period adjustment

Schedule Page: 326.2 Line No.: 8 Column: k
Prior period adjustment

Schedule Page: 326.2 Line No.: 14 Column: k
Prior period adjustment

Schedule Page: 326.3 Line No.: 4 Column: k
Formerly John Deere Renewables, L.L.C.

Schedule Page: 326.3 Line No.: 5 Column: k
Prior period adjustment

Schedule Page: 326.3 Line No.: 8 Column: k
Prior period adjustment

Schedule Page: 326.3 Line No.: 12 Column: k
Prior period adjustment

Schedule Page: 326.4 Line No.: 1 Column: l
Miscellaneous

Schedule Page: 326.4 Line No.: 3 Column: k
Prior period adjustment

Schedule Page: 326.4 Line No.: 6 Column: k
Prior period adjustment

Schedule Page: 326.4 Line No.: 8 Column: l

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Financial trading

Schedule Page: 326.4 Line No.: 10 Column: l

Financial trading

Schedule Page: 326.4 Line No.: 11 Column: j

Capacity credits

Schedule Page: 326.4 Line No.: 12 Column: l

Financial trading

Schedule Page: 326.5 Line No.: 7 Column: l

Prior period adjustment

Schedule Page: 326.5 Line No.: 8 Column: l

Financial trading

Schedule Page: 326.5 Line No.: 9 Column: k

Prior period adjustment

Schedule Page: 326.5 Line No.: 12 Column: k

Prior period adjustment

Schedule Page: 326.5 Line No.: 14 Column: k

Formerly Minwind Energy, L.L.C.

Schedule Page: 326.6 Line No.: 5 Column: l

Financial trading

Schedule Page: 326.6 Line No.: 8 Column: k

Financial trading

Schedule Page: 326.6 Line No.: 9 Column: k

Prior period adjustment

Schedule Page: 326.6 Line No.: 10 Column: k

Financial trading

Schedule Page: 326.6 Line No.: 11 Column: k

Prior period adjustment

Schedule Page: 326.6 Line No.: 13 Column: k

Prior period adjustment

Schedule Page: 326.7 Line No.: 2 Column: k

Housepower

Schedule Page: 326.7 Line No.: 5 Column: k

Housepower

Schedule Page: 326.7 Line No.: 7 Column: l

Financial trading

Schedule Page: 326.7 Line No.: 14 Column: k

Housepower

Schedule Page: 326.8 Line No.: 4 Column: k

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Prior period adjustment

Schedule Page: 326.8 Line No.: 8 Column: k
Prior period adjustment

Schedule Page: 326.8 Line No.: 10 Column: k
Prior period adjustment

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 Classification (d)
1	East Grand Forks, City of	WAPA	East Grand Forks, City of	OS
2	Granite Falls, City of	WAPA	Granite Falls, City of	OS
3	Great River Energy	Various	Various	FNO
4	Midcontinent ISO (MISO)	Various	Various	
5	Missouri River Energy Services (MRES)	Various	Various	FNO
6	Sioux Falls, City of	WAPA	Sioux Falls, City of	OS
7	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS
8	Southern MN Municipal Power Agency	Various	Various	FNO
9	University of North Dakota	WAPA	University of North Dakota	OS
10	Wisconsin Public Power (WPPI)	MP	WPPI	OS
11				
12				
13				
14				
15				
16				
17				
18				
19	**Footnote from page 106b			
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation 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)	
483	WAPA	East Grand Forks, C				1
436	WAPA	Granite Falls, City				2
Various	Various	Various				3
MISO OATT	Various	Various				4
304	Various	Various				5
484	WAPA	Sioux Falls, City of				6
385	WAPA	SDSP				7
304	Various	Various				8
440	WAPA	UND				9
466	BOSWE44G22.8	WPPI-West				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
			0	0	0	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
		50,703	50,703	1
		16,154	16,154	2
39,024,122			39,024,122	3
127,189,503	56,242,913		183,432,416	4
4,956,351			4,956,351	5
		182,008	182,008	6
		13,536	13,536	7
6,727,219			6,727,219	8
		62,627	62,627	9
		40,320	40,320	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
177,897,195	56,242,913	365,348	234,505,456	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 2 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 3 Column: e

28 and 304

Schedule Page: 328 Line No.: 4 Column: d

FNO, LFP, SFP, NF

Schedule Page: 328 Line No.: 4 Column: l

MISO Schedule 26-A revenue

Schedule Page: 328 Line No.: 6 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 7 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 9 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 10 Column: m

Meter Charge

Schedule Page: 328 Line No.: 19 Column: a

Revenues from Transmission of Electricity of Others (account 456.1). The revenue credit from transmission of electricity of others included in the formula are from loads that are not included in the formula divisor, and for transmission charges associated with Schedule 26, 26A, 37, and 38 of the MISO OATT.

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 Tariff (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				

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Basin Electric Pwr Coop	OS					2,400	2,400
2	Central MN Muni Pwr	FNS			844,933			844,933
3	Dairyland Power	OS					19,564	19,564
4	East River Electric Pwr	OLF			208,100			208,100
5	Great River Energy	FNS			34,161,694			34,161,694
6	McLeod Coop Pwr Assn	OLF			24,228			24,228
7	MISO				95,662,187	56,437,310		152,099,497
8	MMPA	FNS			1,097,057			1,097,057
9	Minnkota Pwr Coop	OLF				20,225	780,000	800,225
10	MRES	FNS			1,743,708			1,743,708
11	NWEC	FNS			604,663			604,663
12	Otter Tail Pwr Co	OS					877,631	877,631
13	SMMPA	FNS			12,849,335			12,849,335
14	SPP	FNS			57,463	293		57,756
15	Stearns Coop Electric					526	2,796	3,322
16	Rochester Public Util	FNS			1,534,210			1,534,210
	TOTAL				148,787,578	56,458,354	1,682,391	206,928,323

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: g

Meter Agent Service Charges

Schedule Page: 332 Line No.: 3 Column: g

Facility Charges

Schedule Page: 332 Line No.: 4 Column: b

Termination date - 10/31/2017

Schedule Page: 332 Line No.: 6 Column: b

Two year notification required for termination

Schedule Page: 332 Line No.: 7 Column: b

LFP, FNS, FNO

Schedule Page: 332 Line No.: 7 Column: f

MISO Schedule 26-A expense & MISO Admin FERC fee

Schedule Page: 332 Line No.: 9 Column: b

Four year notification required for termination

Schedule Page: 332 Line No.: 9 Column: g

Fixed Transmission Service Charge

Schedule Page: 332 Line No.: 12 Column: g

Interconnection Upgrade fixed charge

Schedule Page: 332 Line No.: 15 Column: b

OS, LFP

Two year notification required for termination

Schedule Page: 332 Line No.: 15 Column: g

Fixed Facility Charge

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,779,839
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	372,925
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	265
6	Director Fees and Expenses	1,259,487
7	SEC Filing Expenses	39,435
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		
41		
42		
43		
44		
45		
46	TOTAL	3,451,951

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition 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			28,687,686		28,687,686
2	Steam Production Plant	89,107,387	-4,403,223		-1,131,786	83,572,378
3	Nuclear Production Plant	134,025,841	19,480,657			153,506,498
4	Hydraulic Production Plant-Conventional	1,342,842			-70,245	1,272,597
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	107,691,030	3,089,130	239,197	-2,665,188	108,354,169
7	Transmission Plant	64,110,064	5,255		-1,301,618	62,813,701
8	Distribution Plant	106,035,886	48,770			106,084,656
9	Regional Transmission and Market Operation					
10	General Plant	25,402,068			-2,396	25,399,672
11	Common Plant-Electric	28,171,727	-316,502	26,029,882		53,885,107
12	TOTAL	555,886,845	17,904,087	54,956,765	-5,171,233	623,576,464

B. Basis for Amortization Charges

ACCOUNT 404
Column (d) Computer software is amortized over its expected useful life of 3, 5, 7, 10 and 15 years

ACCOUNT 405
Column (e) Prefunded AFUDC recorded as Other Deferred Credits (Account 253) is amortized over the life of the property, and thus appears as a credit to expense

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						
13	310	8,530					
14	311	288,578					
15	312	1,433,113					
16	314	306,302					
17	315	184,518					
18	316	54,021					
19	317	793					
20	Subtotal Steam Prod	2,275,855					
21							
22	Nuclear Production						
23	320	1,762					
24	321	545,033					
25	322	1,646,184					
26	323	538,246					
27	324	474,824					
28	325	206,062					
29	326	237,934					
30	Subtotal Nuclear Prod	3,650,045					
31							
32	Hydro Production						
33	330	1,693					
34	331	1,388					
35	332	10,818					
36	333	10,048					
37	334	3,257					
38	33	61					
39	337						
40	Subtotal Hydro Prod	27,265					
41							
42	Other Production						
43	340	21,948					
44	341	260,345					
45	342	84,553					
46	344	2,182,186					
47	345	270,489					
48	346	31,359					
49	347	77,834					
50	348	4,129					

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	Subtotal Other Prod	2,932,843					
13							
14	Transmission						
15	350	157,441					
16	352	105,042					
17	353	1,198,293					
18	354	118,534					
19	355	1,356,258					
20	356	537,010					
21	357	27,443					
22	358	33,969					
23	359.1	173					
24	Subtotal Transmission	3,534,163					
25							
26	Distribution						
27	360	16,917					
28	361	50,213					
29	362	634,910					
30	364	403,228					
31	365	453,725					
32	366	293,480					
33	367	1,127,782					
34	368	424,229					
35	368	21,877					
36	369	83,107					
37	369	218,861					
38	370	110,216					
39	371	19,791					
40	371	1,635					
41	371	1,280					
42	373	69,621					
43	374	3,770					
44	Subtotal Distribution	3,934,642					
45							
46	General						
47	389	4,462					
48	390	64,365					
49	391	27,785					
50	391	35,128					

Name of Respondent
Northern States Power Company (Minnesota)

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/06/2018

Year/Period of Report
End of 2017/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	2,671					
13	392	31,201					
14	392	18,524					
15	392	104,146					
16	393	1,640					
17	394	85,601					
18	395	3,104					
19	396	45,619					
20	397	16,989					
21	397	15,539					
22	397	50,564					
23	397	7,084					
24	398	3,030					
25	Subtotal General	517,452					
26							
27	TOTAL	16,872,265					
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 1 Column: d

The Amortization of Limited Term Electric Plant within Account 404 includes the following:

Intangible Plant	\$ 16,079,182
Nuclear Production Plant	12,501,676
Hydraulic Production Plant-Conventional	106,828
	\$ 28,687,686

Schedule Page: 336 Line No.: 7 Column: b

Transmission Serving Production	\$ 1,733,930
---------------------------------	--------------

Schedule Page: 336 Line No.: 8 Column: b

Distribution Serving Production	\$ 76,904
---------------------------------	-----------

Schedule Page: 336.1 Line No.: 34 Column: a

Line Transformers

Schedule Page: 336.1 Line No.: 35 Column: a

Line Capacitors

Schedule Page: 336.1 Line No.: 36 Column: a

Overhead Services

Schedule Page: 336.1 Line No.: 37 Column: a

Underground Services

Schedule Page: 336.1 Line No.: 39 Column: a

Installation on Customer Premises (Minnesota)

Schedule Page: 336.1 Line No.: 40 Column: a

Installation on Customer Premises (South Dakota)

Schedule Page: 336.1 Line No.: 41 Column: a

Installation on Customer Premises (North Dakota)

Schedule Page: 336.1 Line No.: 49 Column: a

Office Furniture and Equipment

Schedule Page: 336.1 Line No.: 50 Column: a

Network Equipment

Schedule Page: 336.2 Line No.: 12 Column: a

Transportation Equipment - Automobiles

Schedule Page: 336.2 Line No.: 13 Column: a

Transportation Equipment - Light Trucks

Schedule Page: 336.2 Line No.: 14 Column: a

Transportation Equipment - Trailers

Schedule Page: 336.2 Line No.: 15 Column: a

Transportation Equipment - Heavy Trucks

Schedule Page: 336.2 Line No.: 19 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	\$ 11,216,900	\$ 156,542,000
396 Power Operated Equipment	3,780,574	45,619,000
Total	\$ 14,997,474	\$ 202,161,000

Schedule Page: 336.2 Line No.: 20 Column: a

Communication Equipment

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 336.2 Line No.: 21 Column: a

Communication Equipment - Two Way

Schedule Page: 336.2 Line No.: 22 Column: a

Communication Equipment - EMS

Schedule Page: 336.2 Line No.: 23 Column: a

Communication Equipment - AMR

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) Column (c) through (g):

Subaccounts 311-348: A remaining life technique is applied to each generating facility. No changes to the underlying factors presented in columns (c) through (g) have occurred since filing the 2016 FERC Form 1.

(3) P337 Line 23 - 29 (d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning costs are recovered using an external sinking fund calculation.

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	MINNESOTA PUBLIC UTILITIES COMMISSION				
2	GR15-826 2016 Retail Rate Case		1,285,172	1,285,172	
3	Assessments	4,674,238		4,674,238	
4	Assessments	594,596		594,596	
5					
6	NORTH DAKOTA PUBLIC SERVICE COMMISSION				
7	Assessments	263,112		263,112	
8	Assessments	252		252	
9					
10	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION				
11	EL14-058 2014 Retail Rate Case		119,193	119,193	
12	Assessments	337,591		337,591	
13					
14	Other				
15	Mandated Notices		3,479	3,479	
16	Mandated Notices		7	7	
17	Mandated Inserts		31,778	31,778	
18	Mandated Inserts		304	304	
19	Miscellaneous		226,142	226,142	
20	Miscellaneous		6,758	6,758	
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	TOTAL	5,869,789	1,672,833	7,542,622	

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	1,285,172		186	556,675		2
Electric	928	4,674,238					3
Gas	928	594,596					4
							5
							6
Electric	928	263,112					7
Gas	928	252					8
							9
							10
Electric	928	119,193		186	119,193		11
Electric	928	337,591					12
							13
							14
Electric	928	3,479					15
Gas	928	7					16
Electric	928	31,778					17
Gas	928	304					18
Electric	928	226,142					19
Gas	928	6,758					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
		7,542,622			675,868		46

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 350 Line No.: 2 Column: k
 GR15-826 - 48 month amortization period ending Dec. 31, 2019.

Schedule Page: 350 Line No.: 11 Column: k
 EL14-058 - 36 month amortization period ending Dec. 31, 2017.

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: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute
2		
3	B(2)	Edison Electric Institute
4		
5	B(4)	Renewable Development Fund
6		
7	B(5)	Total
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		

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)		
	3,043,288	Various	3,043,288		1
					2
	896,540	Various	896,540		3
					4
	1,920,090	253	1,920,090		5
					6
	5,859,918		5,859,918		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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		04/06/2018	2017/Q4
FOOTNOTE DATA			

Schedule Page: 352 Line No.: 1 Column: e

Accounts charged:	
107	\$260,000
517	2,256,482
524	25,613
921	47,407
930.2	453,786
	\$3,043,288

Schedule Page: 352 Line No.: 3 Column: e

Accounts charged:	
426.1	\$14,518
426.4	108,938
560	58,472
930.2	714,612
	\$896,540

Schedule Page: 352 Line No.: 5 Column: b

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C3.779. Funding through this statute supports energy production and research and development of alternative sources of electricity. The projects listed below support the research and development of renewable sources of electricity. Also see page 269, Other Deferred Credits (Account 253).

Research Projects	
University of Minnesota-Dairy	\$101,820
University of Minnesota-VWS	229,981
University of Minnesota-Noise	234,264
University of Minnesota-NRRI Torrefact	17,481
Interphases Solar	131,023
University of Minnesota-Gasification	139,221
University of Minnesota	1,000,000
Barr Engineering	66,300
	\$1,920,090

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	5,328,557		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	5,801,979		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	764,033		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	20,359		
54	Other Gas Supply (Enter Total of lines 33 and 45)	343,590		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	1,483,091		
56	Transmission (Lines 35 and 47)	1,402,721		
57	Distribution (Lines 36 and 48)	21,129,474		
58	Customer Accounts (Line 37)	3,324,424		
59	Customer Service and Informational (Line 38)	968,141		
60	Sales (Line 39)	582		
61	Administrative and General (Lines 40 and 49)	7,112,525		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	36,548,940	1,113,718	37,662,658
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	471,293,133	12,314,846	483,607,979
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	92,302,249	39,834,331	132,136,580
69	Gas Plant	5,943,615	5,443,756	11,387,371
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	98,245,864	45,278,087	143,523,951
72	Plant Removal (By Utility Departments)			
73	Electric Plant	10,919,182	4,638,797	15,557,979
74	Gas Plant	521,770	633,938	1,155,708
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	11,440,952	5,272,735	16,713,687
77	Other Accounts (Specify, provide details in footnote):			
78	Regulatory Assets (Acct No. 182.3)	7,766,214	91,380	7,857,594
79	Preliminary Survey and Investigation (Acct No. 183)	-379,863	4,961	-374,902
80	Misc Deferred Debits (Acct No. 186)	470	3,611	4,081
81	Misc Deferred Credits (Acct No. 253)	224		224
82	Regulatory Liabilities (Acct No. 254)	124,811	2,391	127,202
83	Nonutility (Accts No. 416-417.1)	794,240	11,215	805,455
84	Misc Income and Deductions (Accts No. 426.1-5)	578,114	20,706	598,820
85	Nonutility CWIP and RWIP	8,310		8,310
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	8,892,520	134,264	9,026,784
96	TOTAL SALARIES AND WAGES	589,872,469	62,999,932	652,872,401

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 79 Column: b
 Negative balance due to transfer of prior-year labor to capital construction-electric

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	--	--

COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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.

Instruction 1:

Account -----	Allocated to Utility Departments		Cost at Dec. 31, 2017 -----
	Electric -----	Gas -----	
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)			
301 Organization	\$92,046	\$8,562	\$100,608
303 Computer Software	338,556,284	31,491,026	370,047,310
	-----	-----	-----
Total intangible plant	\$338,648,330	\$31,499,588	\$370,147,918
389 Land and land rights	\$5,727,653	\$469,255	\$6,196,908
390 Structures and improvements	166,591,936	13,648,529	180,240,465
391 Office furniture and equipment	126,043,901	10,326,513	136,370,414
392 Transportation equipment	9,216,633	1,270,519	10,487,152
393 Stores equipment	227,522	18,640	246,162
394 Tools/shop/garage equipment	4,067,046	333,205	4,400,251
395 Laboratory equipment	-	-	-
396 Power operated equipment	591,963	81,713	673,676
397 Communications equipment	732,705	60,029	792,734
398 Miscellaneous equipment	421,611	34,541	456,152
399.1 Asset retirement costs for general plant	601,181	49,254	650,435
	-----	-----	-----
TOTAL	\$652,870,481	\$57,791,786	\$710,662,267
COMMON UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)			
389 Land and Land Rights	\$ -	\$ -	\$ -
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS (ACCOUNT 107)			
General Plant	\$ 52,557,398	\$4,698,941	\$ 57,256,339

Instruction 2:

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	--	--

COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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.

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNTS 108 AND 111)

General Plant	\$236,615,067	\$21,297,277	\$257,912,344
---------------	---------------	--------------	---------------

Common utility plant and accumulated provision for depreciation has been allocated to the various utilities on the basis of customers, employee labor, or direct assignment based on actual use.

"Non-Legal" ARO
Balances

Common General	\$ (7,397,596)
Common Intangible	-
Total Common	\$ (7,397,596)

Instruction 3:

COMMON UTILITY PLANT EXPENSES

	Electric	Gas	Total
403 Depreciation Expense	\$28,171,727	\$2,368,902	\$30,540,629
403.1 Depreciation Expense - ARC	(316,502)	(25,968)	(342,470)
404 Amortization of limited term plant	26,029,882	4,438,802	30,468,684
407.4 Amortization of regulatory credits	264,166	21,653	285,819
411.1 Accretion expense	52,338	4,315	56,653
TOTAL	\$54,201,611	\$6,807,704	\$61,009,315

Basis of allocation of Common Utility Plant expenses:

From Through Allocation Methods

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report End of <u>2017/Q4</u>
---	---	--	--

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.

403	403	Depreciation allocator (excluding integrated software)
404	404	Software amortization allocator
407.4	407.4	3-factor (operating revenue, plant in service, supervised O&M)
411.1	411.1	3-factor (operating revenue, plant in service, supervised O&M)

Common Utility Plant and Accumulated Provision for Depreciation and Amortization. The Form 1 reports common utility plant and accumulated provision for depreciation and amortization allocated to the electric department at the end of the year. The Company uses a 13-month average calculation for the electric department common utility plant and accumulated provision for depreciation and amortization in the formula.

Common plant operation and maintenance charges and rents are not separately accounted for and, therefore, are not available.

Instruction 4: The use of common utility plant classification was recommended by Federal Power Commission letter dated Aug. 14, 1969.

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)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	MISO				
8	Net Purchases (Account 555)	3,283,572	22,295,751	41,050,879	54,175,895
9	Net Sales (Account 447)	(24,043,068)	(38,886,669)	(50,060,330)	(77,549,009)
10	Transmission Rights	(3,005,525)	(11,218,710)	(34,361,388)	(41,397,484)
11	Ancillary Services	186,909	508,123	641,683	953,776
12	Other Items (list separately)				
13	Admin Fees	2,589,889	4,760,789	6,953,504	9,557,643
14	Net Purchases for Storage Operations	3,485	2,942	(17,647)	(41,935)
15	ERCOT				
16	Net Purchases (Account 555)	(123,937)	(81,383)	503,022	464,322
17	Net Sales (Account 447)				
18	Transmission Rights				
19	Ancillary Services				
20	Other Items				
21	Uplift Charges	162	370	470	796
22	NEISO				
23	Net Purchases (Account 555)				
24	Net Sales (Account 447)				
25	Ancillary Services				
26	Other Items				
27	Admin Fees	2,151	5,767	10,094	14,583
28	Uplift Charges				
29	NYISO				
30	Net Purchases (Account 555)	13,203	(68,678)	(68,678)	(68,678)
31	Transmission Rights				
32	Admin Fees	(4,442)	(2,987)	(2,987)	(2,987)
33	PJM				
34	Net Purchases (Account 555)	98,880	127,663	(313,025)	(164,417)
35	Net Sales (Account 447)				
36	Transmission Rights	13,530	13,530	(738)	8,848
37	Ancillary Services				
38	Other Items				
39	Admin Fees	2,000	6,981	12,116	20,251
40	Uplift Charges	(233,983)	(207,680)	(183,463)	(147,176)
41	SPP				
42	Net Purchases (Account 555)	18,169	18,241	42,237	76,819
43	Uplift Charges	329	945	1,295	1,618
44	Transmission Rights		(1,282)	(1,282)	(1,282)
45	Ancillary Services	390	686	961	1,368
46	TOTAL	(21,198,286)	(22,725,601)	(35,793,277)	(54,097,049)

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			7,982,513			1,167,234
2	Reactive Supply and Voltage			8,770,801			8,811,407
3	Regulation and Frequency Response			1,734,764			2,724,468
4	Energy Imbalance						
5	Operating Reserve - Spinning			1,876,034			2,717,674
6	Operating Reserve - Supplement			550,131			541,436
7	Other						86,413
8	Total (Lines 1 thru 7)			20,914,243			16,048,632

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: b

Lines 1- 7: Number of units not available

Schedule Page: 398 Line No.: 1 Column: e

Lines 1-7: Volume of units is not available

Schedule Page: 398 Line No.: 7 Column: g

NSPM MISO NSPP DA_RC_AMT	\$ 72,089
NSPM MISO NSPP RT_RC_AMT	14,324
	<u>\$ 86,413</u>

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: Northern States Power Co. Integrated 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	7,502	5	18	6,291	1,527				
2	February	7,103	1	19	5,919	1,485				
3	March	6,615	15	9	5,513	1,386				
4	Total for Quarter 1				17,723	4,398				
5	April	6,240	27	11	5,205	1,257				
6	May	7,234	16	17	6,003	1,423				
7	June	9,269	13	18	7,742	1,822				
8	Total for Quarter 2				18,950	4,502				
9	July	9,968	17	18	8,318	1,983				
10	August	9,353	1	16	7,742	1,914				
11	September	9,679	22	17	8,085	1,894				
12	Total for Quarter 3				24,145	5,791				
13	October	6,711	3	14	5,639	1,310				
14	November	6,967	16	18	5,726	1,523				
15	December	7,559	27	18	6,196	1,685				
16	Total for Quarter 4				17,561	4,518				
17	Total Year to Date/Year				78,379	19,209				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 1 Column: b

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin, (collectively, the "NSP Companies"). The construction, operation and maintenance of the two companies' systems is coordinated.

Schedule Page: 400 Line No.: 1 Column: e

"Firm Network Service - For Self" includes load in the Otter Tail Power Balancing Authority (OTP BA). The NSP Companies' load in the OTP BA at the OTP coincident peak is:

January	357
February	342
March	323
April	260
May	231
June	336
July	363
August	332
September	345
October	276
November	297
December	338
	3,800

"Firm Network Service - For Self" does not include the NSP Companies' load on transmission assets in the Great River Energy Balancing Authority (GRE BA). The NSP Companies' load in the GRE BA at the Great River Energy coincident peak is:

January	68
February	60
March	57
April	45
May	43
June	50
July	68
August	64
September	42
October	47
November	52
December	71
	667

Name of Respondent
Northern States Power Company (Minnesota)

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/06/2018

Year/Period of Report
End of 2017/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	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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									

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)	34,065,667
3	Steam	13,565,181	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,928,421
4	Nuclear	13,904,321	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,654,822
5	Hydro-Conventional	74,096	25	Energy Furnished Without Charge	347
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	55,703
7	Other	7,693,054	27	Total Energy Losses	1,374,380
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	48,079,340
9	Net Generation (Enter Total of lines 3 through 8)	35,236,652			
10	Purchases	12,842,688			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
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)	48,079,340			

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: Northern States Power Co. Integrated System

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	4,395,193	744,089	5,379	5	1800
30	February	3,587,750	467,654	5,079	1	1900
31	March	4,121,658	760,872	4,691	15	900
32	April	3,351,474	331,484	4,485	26	1200
33	May	3,691,923	539,829	5,242	16	1700
34	June	3,979,288	404,221	6,725	13	1800
35	July	4,585,417	430,520	7,371	17	1800
36	August	4,023,164	401,186	6,749	1	1600
37	September	3,908,605	449,279	6,995	22	1700
38	October	3,948,594	689,184	4,764	3	1400
39	November	4,020,751	641,505	4,879	16	1800
40	December	4,465,523	794,999	5,271	27	1800
41	TOTAL	48,079,340	6,654,822			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 27 Column: b

MWH stored in Wind2Battery project on Dec. 31, 2017

0.422

Schedule Page: 401 Line No.: 29 Column: Sys

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin. The construction, operation and maintenance of the two companies' systems is coordinated. This table shows the integrated system peak and the demand of each jurisdiction at the time of the integrated system peak. The monthly peaks reported in column d of page 401b are the sums of the monthly peaks for the states of Wisconsin and Michigan shown below.

Day	Hour	Integrated System	Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)	
			Minnesota	North Dakota	South Dakota	Wisconsin	Michigan
5-Jan	1800	6,476	4,659	388	332	1,071	26
1-Feb	1900	6,104	4,396	375	308	1,000	25
15-Mar	900	5,682	4,072	328	291	968	23
26-Apr	1200	5,397	3,911	304	270	892	20
16-May	1700	6,203	4,602	280	360	942	19
13-Jun	1800	7,883	5,978	304	443	1,138	20
17-Jul	1800	8,546	6,484	403	484	1,155	20
1-Aug	1600	7,979	5,921	379	449	1,208	22
22-Sep	1700	8,246	6,216	324	455	1,227	24
3-Oct	1400	5,762	4,240	251	273	979	19
16-Nov	1800	5,914	4,262	328	289	1,014	21
27-Dec	1800	6,410	4,542	392	337	1,114	25

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: <i>Riverside</i> (b)	Plant Name: <i>Wilmarth</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Combined Cycle	Steam				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional				
3	Year Originally Constructed	1911	1948				
4	Year Last Unit was Installed	2009	1951				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	585.90	25.00				
6	Net Peak Demand on Plant - MW (60 minutes)	512	20				
7	Plant Hours Connected to Load	4117	7360				
8	Net Continuous Plant Capability (Megawatts)	500	18				
9	When Not Limited by Condenser Water	500	18				
10	When Limited by Condenser Water	454	18				
11	Average Number of Employees	23	27				
12	Net Generation, Exclusive of Plant Use - KWh	1597803172	88062421				
13	Cost of Plant: Land and Land Rights	450133	499773				
14	Structures and Improvements	52352107	8200994				
15	Equipment Costs	256484156	47086952				
16	Asset Retirement Costs	864346	962921				
17	Total Cost	310150742	56750640				
18	Cost per KW of Installed Capacity (line 17/5) Including	529.3578	2270.0256				
19	Production Expenses: Oper, Supv, & Engr	537134	360106				
20	Fuel	51327469	524942				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	97865	2186499				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	2043497	84826				
26	Misc Steam (or Nuclear) Power Expenses	853105	568096				
27	Rents	521592	285138				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	311527	39320				
30	Maintenance of Structures	782517	221734				
31	Maintenance of Boiler (or reactor) Plant	22380	1645976				
32	Maintenance of Electric Plant	6165201	1232260				
33	Maintenance of Misc Steam (or Nuclear) Plant	286668	879551				
34	Total Production Expenses	62948955	8028448				
35	Expenses per Net KWh	0.0394	0.0912				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas	Oil	RDF	Gas	Wood
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF	Barrels	Tons	MCF	Tons
38	Quantity (Units) of Fuel Burned	0	11078777	0	149961	28549	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1050	0	6051	1062	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	4.633	0.000	2.014	5.021	0.000
41	Average Cost of Fuel per Unit Burned	0.000	4.633	0.000	11.725	5.021	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	4.410	0.000	0.969	4.728	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.032	0.000	0.000	0.020	0.000
44	Average BTU per KWh Net Generation	0.000	7283.840	0.000	0.000	20952.130	0.000

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: <u>Sherburne County</u> (b)	Plant Name: <u>Granite City</u> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Gas Turbine				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Ind Enclosures				
3	Year Originally Constructed	1976	1969				
4	Year Last Unit was Installed	1987	1969				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2469.32	72.00				
6	Net Peak Demand on Plant - MW (60 minutes)	1906	55				
7	Plant Hours Connected to Load	8760	28				
8	Net Continuous Plant Capability (Megawatts)	1879	64				
9	When Not Limited by Condenser Water	1879	64				
10	When Limited by Condenser Water	1879	52				
11	Average Number of Employees	215	0				
12	Net Generation, Exclusive of Plant Use - KWh	10457101435	-204760				
13	Cost of Plant: Land and Land Rights	5951721	40240				
14	Structures and Improvements	225433132	1241718				
15	Equipment Costs	1220886318	7531945				
16	Asset Retirement Costs	-1132408	68958				
17	Total Cost	1451138763	8882861				
18	Cost per KW of Installed Capacity (line 17/5) Including	587.6674	123.3731				
19	Production Expenses: Oper, Supv, & Engr	2262200	0				
20	Fuel	251379845	30111				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	10191212	0				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	3551831	25				
26	Misc Steam (or Nuclear) Power Expenses	9820159	41142				
27	Rents	1356371	2516				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	1285206	0				
30	Maintenance of Structures	2104163	53828				
31	Maintenance of Boiler (or reactor) Plant	13105448	0				
32	Maintenance of Electric Plant	3040738	16203				
33	Maintenance of Misc Steam (or Nuclear) Plant	7313022	0				
34	Total Production Expenses	305410195	143825				
35	Expenses per Net KWh	0.0292	-0.7024				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Gas	Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels	MCF	Barrels		
38	Quantity (Units) of Fuel Burned	6352148	0	21258	5702	0	113
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8644	0	138195	1000	0	138942
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	37.032	0.000	71.201	3.963	0.000	66.555
41	Average Cost of Fuel per Unit Burned	39.298	0.000	71.201	3.963	0.000	66.555
42	Average Cost of Fuel Burned per Million BTU	2.273	0.000	12.267	3.963	0.000	11.405
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.020	0.000	0.000	-0.150	0.000
44	Average BTU per KWh Net Generation	0.000	10513.200	0.000	0.000	-31181.370	0.000

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: <i>Angus Anson</i> (b)	Plant Name: <i>Black Dog Unit 5</i> (c)			
		Gas Turbines	Combined Cycle			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		Combined Cycle			
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional			
3	Year Originally Constructed	1994	1987			
4	Year Last Unit was Installed	2005	2002			
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	405.66	324.79			
6	Net Peak Demand on Plant - MW (60 minutes)	330	328			
7	Plant Hours Connected to Load	2056	3310			
8	Net Continuous Plant Capability (Megawatts)	386	298			
9	When Not Limited by Condenser Water	386	298			
10	When Limited by Condenser Water	327	282			
11	Average Number of Employees	8	26			
12	Net Generation, Exclusive of Plant Use - KWh	70126467	689798372			
13	Cost of Plant: Land and Land Rights	1156667	952692			
14	Structures and Improvements	7719722	49991612			
15	Equipment Costs	114588068	187049580			
16	Asset Retirement Costs	658999	48341			
17	Total Cost	124123456	238042225			
18	Cost per KW of Installed Capacity (line 17/5) Including	305.9790	732.9112			
19	Production Expenses: Oper, Supv, & Engr	89744	115642			
20	Fuel	3039318	20051517			
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	40898	26756			
26	Misc Steam (or Nuclear) Power Expenses	452603	98320			
27	Rents	82588	149942			
28	Allowances	0	0			
29	Maintenance Supervision and Engineering	3706	331670			
30	Maintenance of Structures	744790	694377			
31	Maintenance of Boiler (or reactor) Plant	0	0			
32	Maintenance of Electric Plant	746580	849696			
33	Maintenance of Misc Steam (or Nuclear) Plant	24315	386029			
34	Total Production Expenses	5224542	22703949			
35	Expenses per Net KWh	0.0745	0.0329			
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil	Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Barrels	MCF		
38	Quantity (Units) of Fuel Burned	794569	0	513	0	4718370
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1065	0	138009	0	1058
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.780	0.000	70.358	0.000	4.250
41	Average Cost of Fuel per Unit Burned	3.780	0.000	70.358	0.000	4.250
42	Average Cost of Fuel Burned per Million BTU	3.550	0.000	12.138	0.000	4.016
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.040	0.000	0.000	0.030
44	Average BTU per KWh Net Generation	0.000	12105.270	0.000	0.000	7237.560

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: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
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	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

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: <i>A S King</i> (d)	Plant Name: <i>Prairie Island</i> (e)	Plant Name: <i>Blue Lake</i> (f)	Line No.						
Steam	Nuclear	Gas Turbine	1						
Conventional	Conventional	Ind Enclosures	2						
1968	1973	1974	3						
1968	1974	2005	4						
598.40	1186.20	559.32	5						
532	1116	369	6						
6833	8760	462	7						
511	1092	545	8						
511	1092	545	9						
511	1040	453	10						
82	673	3	11						
2913347900	8744731000	79917000	12						
1335100	969282	141878	13						
38715830	322664775	1623647	14						
657806782	1703019911	94675144	15						
3833412	-139278542	94817	16						
701691124	1887375426	96535486	17						
1172.6122	1591.1106	172.5944	18						
649242	39416155	94824	19						
66253379	73389169	4835220	20						
0	4957422	0	21						
7308288	28208500	0	22						
0	0	0	23						
0	0	0	24						
364585	2503716	151885	25						
2740640	76292057	32760	26						
998990	6761886	59775	27						
0	0	0	28						
1365480	2743204	2389	29						
1652987	419818	217669	30						
7275984	24176832	0	31						
1590651	7635084	701535	32						
2071898	20755162	174	33						
92272124	287259005	6096231	34						
0.0317	0.0328	0.0763	35						
Coal	Gas	Oil		Nuclear		Gas		Oil	36
Tons	MCF	Barrels		Grams U-235		MCF		Barrels	37
1646428	49877	45	0	832763	0	851485	0	2645	38
8898	1061	137894	0	110721	0	1060	0	138002	39
37.472	3.794	78.029	0.000	0.000	0.000	5.376	0.000	97.535	40
40.162	3.794	78.029	0.000	0.000	0.000	5.376	0.000	97.535	41
2.257	3.577	13.473	0.000	0.800	0.000	5.070	0.000	16.828	42
0.000	0.020	0.000	0.000	0.010	0.000	0.000	0.060	0.000	43
0.000	10075.100	0.000	0.000	10544.470	0.000	0.000	11488.010	0.000	44

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: <i>Inver Hills</i> (d)	Plant Name: <i>High Bridge 7, 8, 9</i> (e)	Plant Name: <i>Monticello</i> (f)	Line No.						
Gas Turbine	Combined Cycle	Nuclear	1						
Ind Enclosures	Conventional	Conventional	2						
1972	1924	1971	3						
1972	2008	1971	4						
280.50	644.06	684.97	5						
175	631	668	6						
142	4884	8052	7						
371	606	646	8						
371	606	646	9						
282	530	617	10						
7	23	525	11						
4539322	1984030000	5159590000	12						
432561	528150	783302	13						
1914621	70931072	236023851	14						
57700009	318690655	1198586556	15						
114211	19394	132475222	16						
60161402	390169271	1567868931	17						
214.4792	605.7965	2288.9600	18						
633	628383	26052591	19						
480671	55215194	40972655	20						
0	0	4207868	21						
0	0	21840019	22						
0	0	0	23						
0	0	0	24						
192187	2191229	17697	25						
48625	728299	54761239	26						
60464	529177	4956185	27						
0	0	0	28						
136	492032	2485880	29						
294898	844153	0	30						
0	0	14942183	31						
482221	955952	3960920	32						
3984	99471	10616548	33						
1563819	61683890	184813785	34						
0.3445	0.0311	0.0358	35						
	Gas	Oil		Gas			Nuclear		36
	MCF	Barrels		MCF			Grams U-235		37
0	111743	465	0	13319751	0	0	486114	0	38
0	1059	139782	0	1060	0	0	111193	0	39
0.000	3.978	77.844	0.000	4.145	0.000	0.000	0.000	0.000	40
0.000	3.978	77.844	0.000	4.145	0.000	0.000	0.000	0.000	41
0.000	3.758	13.260	0.000	3.912	0.000	0.000	0.762	0.000	42
0.000	0.110	0.000	0.000	0.030	0.000	0.000	0.010	0.000	43
0.000	26655.950	0.000	0.000	7114.560	0.000	0.000	10479.490	0.000	44

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: <i>Black Dog 3 & 4</i> (d)	Plant Name: <i>Key City</i> (e)	Plant Name: (f)	Line No.
Steam	Gas Turbine		1
Conventional	Ind Enclosures		2
1952	1970		3
1960	1970		4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	-5920	0	12
0	67495	0	13
0	1002265	0	14
0	7597648	0	15
0	0	0	16
0	8667408	0	17
0	0	0	18
269342	0	0	19
4083	0	0	20
0	0	0	21
2855055	0	0	22
0	0	0	23
0	0	0	24
22801	0	0	25
307862	59	0	26
322936	491	0	27
0	0	0	28
26620	0	0	29
630843	1639	0	30
198764	0	0	31
974597	6553	0	32
953716	0	0	33
6566619	8742	0	34
0.0000	-1.4767	0.0000	35
			36
			37
0	41	0	38
0	139766	0	39
0.000	88.014	0.000	40
0.000	88.014	0.000	41
0.000	14.993	0.000	42
0.000	0.080	0.000	43
0.000	6459.460	0.000	44

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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	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	0	0	21
0	0	0	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
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 403 Line No.: -1 Column: e

Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403)

(a) Operating and maintenance costs of the Prairie Island Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.

Schedule Page: 402.1 Line No.: -1 Column: b

Sherburne County Generating Plant Unit 3 is jointly owned by NSP-Minnesota (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). See Note 4 of the Financial Statements on Page 123 for disclosures regarding Sherco Unit 3.

Schedule Page: 403.1 Line No.: -1 Column: f

Instruction 12 - Monticello Nuclear Generating Plant (p. 403.1)

(a) Operating and maintenance costs of the Monticello Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 84 metric tons of uranium metal with a nominal U-235 enrichment of 3.8 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.

Schedule Page: 402 Line No.: 39 Column: e2

Average heat content of fuel burned is MBTU/kg U235.

Schedule Page: 402.1 Line No.: 39 Column: b1

The "Average Heat Content of Fuel Burned" is calculated as:

Coal: Btu/pound
Oil: Btu/ gallons
Gas: Btu/cubic ft

Schedule Page: 402.1 Line No.: 39 Column: f2

Average heat content of fuel burned is in KBTU/gm U235.

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. 2056 Plant Name: Henn Is & Upper Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run of River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1908	
4	Year Last Unit was Installed	1955	
5	Total installed cap (Gen name plate Rating in MW)	13.89	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	12	0
7	Plant Hours Connect to Load	8,599	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	7	0
10	(b) Under the Most Adverse Oper Conditions	6	0
11	Average Number of Employees	3	0
12	Net Generation, Exclusive of Plant Use - Kwh	74,095,544	0
13	Cost of Plant		
14	Land and Land Rights	1,548,707	0
15	Structures and Improvements	1,349,723	0
16	Reservoirs, Dams, and Waterways	8,566,123	0
17	Equipment Costs	13,375,287	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	24,839,840	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,788.3254	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	18,122	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	425,694	0
27	Misc Hydraulic Power Generation Expenses	121,102	0
28	Rents	41,316	0
29	Maintenance Supervision and Engineering	14,841	0
30	Maintenance of Structures	81,785	0
31	Maintenance of Reservoirs, Dams, and Waterways	30,160	0
32	Maintenance of Electric Plant	308,887	0
33	Maintenance of Misc Hydraulic Plant	418	0
34	Total Production Expenses (total 23 thru 33)	1,042,325	0
35	Expenses per net KWh	0.0141	0.0000

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

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 Demand 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)	

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
			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

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	STEAM PLANT					
2						
3	Red Wing	1949	23.00	22.0	106,668,803	64,620,665
4	Minnesota Valley	1932				13,512,002
5	High Bridge 5 & 6	1924				
6						
7						
8	GAS PLANT					
9						
10	West Faribault	1965				
11						
12						
13	INTERNAL COMBUSTION					
14						
15	Dispersed Generation				30,347	2,038,090
16						
17						
18	WIND TURBINE PLANTS					
19						
20	Lake Benton	1997				10,190,362
21	Grand Meadow Wind Farm	2008	100.50	99.8	312,965,640	220,200,621
22	Nobles Wind	2010	201.00	201.2	700,026,790	538,168,364
23	Pleasant Valley	2015	200.00	194.0	832,946,820	353,065,943
24	Borders Wind	2015	150.00	147.1	644,031,696	272,666,884
25	Courtenay Wind	2016	200.00	199.1	777,048,617	298,465,179
26						
27	SOLAR					
28						
29	Photovoltaic Units	1995				306,139
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

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		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
2,809,594	2,408,522	402,606	3,618,126	RDF, Gas	117	3
	106		3,330			4
	48,272		88,135			5
						6
						7
						8
						9
						10
						11
						12
						13
						14
		8,713		Oil	1,689	15
						16
						17
						18
						19
				Wind		20
2,191,051	1,272,797		1,535,351	Wind		21
2,677,455	2,764,396		1,359,365	Wind		22
1,765,330	7,117,878		1,663,360	Wind		23
1,817,779	4,053,789		838,892	Wind		24
1,492,326	4,204,749		129,098	Wind		25
						26
						27
						28
				Solar		29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 1 Column: g
The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(5703;01) CHISAGO CO.	FORBES	500.00	500.00	TOWER	61.45		1
2	(5702;01) FORBES	RIEL (MH)	500.00	500.00	TOWER	203.77		1
3	(0998;01) SIOUX CITY	SPLIT ROCK	345.00	345.00	SINGLE POLE		4.43	1
4			345.00	345.00	SINGLE POLE		0.63	1
5	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.00	345.00	SINGLE POLE	4.91	0.24	1
6	(0996;01) DICKINSON SW	PARKERS LAKE	345.00	345.00	TOWER	0.15	9.60	1
7	(0994;01) ALLEN S KING	CHISAGO CO.	345.00	345.00	SINGLE POLE		31.56	1
8			345.00	345.00	TOWER		6.62	1
9	(0992;02) COON CREEK	SHERBURNE CO.	345.00	345.00	K-FRAME	16.92	0.37	1
10			345.00	345.00	SINGLE POLE		14.66	1
11			345.00	345.00	TOWER		11.43	1
12	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.00	345.00	TOWER		5.81	1
13	(0989;01) BLUE LAKE	INVER HILLS	345.00	345.00	K-FRAME	0.78		1
14			345.00	345.00	SINGLE POLE		0.82	1
15			345.00	345.00	TOWER	3.52	17.16	1
16	(0989;01) INVER HILLS	RED ROCK	345.00	345.00	H-FRAME	0.52		1
17			345.00	345.00	K-FRAME	2.00		1
18			345.00	345.00	TOWER	5.98		1
19	(0988;01) BLUE LAKE	PARKERS LAKE	345.00	345.00	SINGLE POLE		2.18	1
20			345.00	345.00	TOWER		12.61	1
21	(0987;01) PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	20.82	0.20	1
22			345.00	345.00	SINGLE POLE		6.28	1
23			345.00	345.00	TOWER		2.15	1
24			345.00	345.00	TOWER		2.51	1
25	(0986;02) PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	20.99		1
26			345.00	345.00	SINGLE POLE	6.28		1
27			345.00	345.00	TOWER	2.15		1
28			345.00	345.00	TOWER		2.52	1
29	(0985;01) COON CREEK	SHERBURNE CO.	345.00	345.00	H-FRAME	16.13	1.25	1
30			345.00	345.00	K-FRAME	3.37		1
31			345.00	345.00	SINGLE POLE	0.29	0.63	1
32			345.00	345.00	TOWER	5.79	5.67	1
33	(0984;03) COON CREEK	SHERBURNE CO.	345.00	345.00	K-FRAME	18.89		1
34			345.00	345.00	SINGLE POLE	15.13		1
35			345.00	345.00	TOWER	9.43		1
36					TOTAL	5,110.46	587.93	150

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(0984;01) COON CREEK	TERMINAL	345.00	345.00	SINGLE POLE		4.60	1
2			345.00	345.00	TOWER		9.03	1
3	(0982;01) BLUE LAKE	SCOTT CO.	345.00	345.00	TOWER	8.15		1
4	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.00	345.00	K-FRAME	1.86		1
5			345.00	345.00	SINGLE POLE	0.34		1
6	(0982;01) CRANDALL	WILMARTH	345.00	345.00	K-FRAME	50.86		1
7			345.00	345.00	TOWER	1.52		1
8	(0982;01) HELENA	SCOTT CO.	345.00	345.00	K-FRAME	15.01		1
9			345.00	345.00	TOWER	2.16		1
10	(0982;01) HELENA	SHEAS LAKE	345.00	345.00	K-FRAME	7.45		1
11	(0982;01) LAKEFIELD JCT	LAKEFIELD GENERATING	345.00	345.00	K-FRAME	18.37		1
12			345.00	345.00	SINGLE POLE	0.34		1
13	(0982;01) SHEAS LAKE	WILMARTH	345.00	345.00	K-FRAME	23.37		1
14			345.00	345.00	TOWER	1.36		1
15	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.00	345.00	K-FRAME	3.69		1
16			345.00	345.00	TOWER	0.72	15.19	1
17	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.00	345.00	SINGLE POLE	31.38	0.55	1
18			345.00	345.00	TOWER		5.68	1
19	(0980;01) COON CREEK	KOHLMAN LAKE	345.00	345.00	SINGLE POLE	4.60	2.94	1
20			345.00	345.00	TOWER	6.87	5.50	1
21	(0979;01) ADAMS	PLEASANT VALLEY (GRE)	345.00	345.00	K-FRAME	16.83		1
22	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.00	345.00	K-FRAME	13.54		1
23	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.00	345.00	H-FRAME	1.14		1
24			345.00	345.00	K-FRAME	15.15		1
25	(0979;01) NORTH	PRAIRIE ISLAND	345.00	345.00	H-FRAME	1.08		1
26			345.00	345.00	K-FRAME	26.15		1
27			345.00	345.00	TOWER	2.40		1
28	(0978;01) ELM CREEK	MONTICELLO SUB	345.00	345.00	H-FRAME	17.22		1
29			345.00	345.00	K-FRAME	3.37		1
30			345.00	345.00	TOWER	5.51		1
31	(0978;01) ELM CREEK	PARKERS LAKE	345.00	345.00	SINGLE POLE	0.59		1
32			345.00	345.00	TOWER	10.46		1
33	(0977;01) ALLEN S KING	KOHLMAN LAKE	345.00	345.00	TOWER	12.67		1
34	(0977;01) KOHLMAN LAKE	TERMINAL	345.00	345.00	SINGLE POLE	2.94		1
35			345.00	345.00	TOWER	7.20		1
36					TOTAL	5,110.46	587.93	150

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.00	345.00	SINGLE POLE	3.61		1
2			345.00	345.00	TOWER	1.93		1
3	(0976;01) BLUE LAKE	HAMPTON	345.00	345.00	K-FRAME	2.38		1
4			345.00	345.00	K-FRAME	6.17		1
5			345.00	345.00	SINGLE POLE	0.82		1
6			345.00	345.00	TOWER	23.66		1
7	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.00	345.00	TOWER	9.47		1
8	(0976;01) HAMPTON	PRAIRIE ISLAND	345.00	345.00	K-FRAME	16.00		1
9			345.00	345.00	TOWER	3.55		1
10	(0975;01) ALLEN S KING	RED ROCK	345.00	345.00	K-FRAME	5.47		1
11			345.00	345.00	TOWER	19.90		1
12	(0974;01) MANKATO	WILMARTH	345.00	345.00	SINGLE POLE	0.22		1
13	(0973;01) MONTICELLO SUB	QUARRY	345.00	345.00	SINGLE POLE	30.04		1
14	(0972-MN;01) BROOKINGS	HAWKS NEST LAKE	345.00	345.00	SINGLE POLE	18.48		1
15	(0972-SD;01) BROOKINGS	HAWKS NEST LAKE	345.00	345.00	SINGLE POLE	10.42		1
16	(0972;01) HAWKS NEST	LYON CO.	345.00	345.00	SINGLE POLE	30.55		1
17	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.00	345.00	SINGLE POLE	0.42		1
18	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.00	345.00	SINGLE POLE	0.38		1
19	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	345.00	345.00	SINGLE POLE	71.58		1
20	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.00	345.00	2 POLE	3.12		1
21			345.00	345.00	SINGLE POLE	40.24		1
22	(0964;01) HAMPTON	NORTH ROCHESTER	345.00	345.00	SINGLE POLE	37.85		1
23	(0962;01) HAZEL CREEK	LYON CO.	345.00	345.00	SINGLE POLE	24.54		1
24	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.00	345.00	SINGLE POLE	18.10		1
25	(0960;01) CHUB LAKE (GRE)	HELENA	345.00	345.00	SINGLE POLE	20.87		1
26	(0959;02) CEDAR MTN.	HELENA	345.00	345.00	SINGLE POLE		73.06	1
27	(0958;01) CEDAR MTN.	HELENA	345.00	345.00	SINGLE POLE	73.10		1
28	(0957;02) CEDAR MTN.	LYON CO.	345.00	345.00	SINGLE POLE		49.49	1
29	(0956;01) CEDAR MTN.	LYON CO.	345.00	345.00	SINGLE POLE	49.49		1
30	(0955-MN;01) ALEXANDRIA	BISON	345.00	345.00	2 POLE	3.35		1
31			345.00	345.00	SINGLE POLE	100.93		1
32	(0955-ND;01) ALEXANDRIA	BISON	345.00	345.00	SINGLE POLE	34.49		1
33	(0954;01) ALEXANDRIA SW.	QUARRY	345.00	345.00	SINGLE POLE	81.22		1
34	(0953-MN;01) LAKEFIELD	NOBLES CO.	345.00	345.00	SINGLE POLE	22.67		1
35			345.00	345.00	SINGLE POLE	13.27		1
36					TOTAL	5,110.46	587.93	150

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.00	345.00	SINGLE POLE	42.55		1
2	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.00	345.00	SINGLE POLE	4.43		1
3			345.00	345.00	SINGLE POLE	5.26		1
4	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.00	345.00	SINGLE POLE	4.97		1
5	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.00	230.00	SINGLE POLE	19.32		1
6	(0922;01) BOSWELL	CASS LAKE (OTP)	230.00	230.00	SINGLE POLE	51.46		1
7	(0920;01) GLENBOROUGH	PEACE GARDEN	230.00	230.00	H-FRAME	1.98		1
8	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.00	230.00	H-FRAME	54.67		1
9	(0919;01) PAYNESVILLE	WILLMAR (GRE)	230.00	230.00	H-FRAME	2.57		1
10			230.00	230.00	SINGLE POLE	27.17		1
11	(0918;01) SIOUX FALLS	SPLIT ROCK	230.00	230.00	SINGLE POLE	0.96		1
12	(0916;01) GRAND FORKS	PRAIRIE	230.00	230.00	H-FRAME	6.35		1
13			230.00	230.00	SINGLE POLE	0.48		1
14	(0915;01) FARGO (WAPA)	SHEYENNE	230.00	230.00	H-FRAME	4.20	0.03	1
15	(0912;01) DRAYTON	LETELLIER (MANITOBA)	230.00	230.00	H-FRAME	28.66		1
16			230.00	230.00	SINGLE POLE	0.07		1
17	(0911;01) AUDUBON (OTP)	SHEYENNE	230.00	230.00	H-FRAME	1.40		1
18	(0911;01) MAPLE RIVER	SHEYENNE	230.00	230.00	H-FRAME	2.82		1
19			230.00	230.00	TOWER	0.14	3.59	1
20	(0910;01) MAPLE RIVER	WAHPETON (MINNKOTA)	230.00	230.00	TOWER	3.59		1
21	(0909;01) AUDUBON (OTP)	HUBBARD (GRE)	230.00	230.00	H-FRAME	37.75		1
22			230.00	230.00	SINGLE POLE	0.79		1
23	(0902,0921;01) ROCK	RUSH CITY (GRE)	230.00	230.00	SINGLE POLE	10.99		1
24			230.00	230.00	SINGLE POLE	53.91		1
25			230.00	230.00	TOWER	2.78		1
26	(0902;01) BEAR CREEK	ROCK CREEK	230.00	230.00	SINGLE POLE	12.55		1
27	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.00	230.00	H-FRAME	1.35		1
28			230.00	230.00	SINGLE POLE	0.96		1
29			230.00	230.00	TOWER	44.15		1
30	(0900;02) GRANITE FALLS	PANTHER (GRE)	230.00	230.00	K-FRAME	0.18		1
31			230.00	230.00	TOWER	32.66		1
32	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.00	230.00	TOWER	28.45		1
33	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	15.51		1
34	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	11.41		1
35			161.00	161.00	SINGLE POLE	0.44	15.82	1
36					TOTAL	5,110.46	587.93	150

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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	(5306;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	161.00	161.00	SINGLE POLE	16.60		1
2	(5305-MN;01) LAWRENCE	ST CROIX FALLS	161.00	161.00	SINGLE POLE	1.57		1
3			161.00	161.00	UNDERGROU	0.58		1
4	(5301-MN;01) ELK (ALLIANT)	ROCK CO.	161.00	161.00	H-FRAME	5.39		1
5	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.00	161.00	H-FRAME	3.42		1
6			161.00	161.00	SINGLE POLE	0.08		1
7	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.00	161.00	H-FRAME	10.37		1
8			161.00	161.00	SINGLE POLE	0.80		1
9	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.00	161.00	H-FRAME	30.11		1
10			161.00	161.00	SINGLE POLE		1.41	1
11								
12	SUMMARY OF 115 KV		115.00	115.00	Overhead	1,460.77	133.64	
13			115.00	115.00	Underground	13.22		
14	SUMMARY OF 69 KV		69.00	69.00	Overhead	1,475.71	96.56	
15			69.00	69.00	Underground	1.53		
16	SUMMARY OF 34.5 KV		34.50	34.50	Overhead	60.93	31.51	
17			34.50	34.50	Underground	0.59		
18	All Lines							
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,110.46	587.93	150

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)	
9-1192 ACSR	2,237,403	15,845,026	18,082,429					1
9-1192 ACSR	1,723,334	66,434,249	68,157,583					2
6-954 ACSS		670,200	670,200					3
6-954 ACSS/TW								4
6-954 ACSS/TW	139,860	8,455,822	8,595,682					5
6-954 ACSR		564,837	564,837					6
6-954 ACSR		1,648,291	1,648,291					7
6-795 ACSR								8
6-954 ACSR	472,775	3,604,416	4,077,191					9
6-954 ACSR								10
6-954 ACSR								11
6-954 ACSR		196,978	196,978					12
6-795 ACSR	80,238	1,436,429	1,516,667					13
6-795 ACSR								14
6-795 ACSR								15
6-795 ACSR	272,767	1,672,480	1,945,247					16
6-795 ACSR								17
6-795 ACSR								18
6-795 ACSR		478,209	478,209					19
6-795 ACSR								20
6-795 ACSR		2,942,385	2,942,385					21
6-795 ACSR								22
6-795 ACSR								23
6-954 ACSR								24
6-795 ACSR	661,692	6,976,971	7,638,662					25
6-795 ACSR								26
6-795 ACSR								27
6-954 ACSR								28
6-954 ACSR	17,816	15,226,282	15,244,098					29
6-954 ACSR								30
6-954 ACSR								31
6-954 ACSR								32
6-954 ACSR	506,296	7,325,674	7,831,969					33
6-954 ACSR								34
6-954 ACSR								35
	126,838,425	2,092,665,186	2,219,503,600	1,248,687	8,132,482	3,498,285	12,879,454	36

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)	
6-795 ACSR	160,760	2,309,570	2,470,331					1
6-795 ACSR								2
6-795 ACSR	57,938	1,328,115	1,386,052					3
6-795 ACSR	26,720	427,791	454,511					4
6-795 ACSR								5
6-795 ACSR	639,711	9,952,465	10,592,176					6
6-795 ACSR								7
6-795 ACSR	122,435	2,880,878	3,003,313					8
6-795 ACSR								9
6-795 ACSR	102,880	1,827,727	1,930,607					10
6-795 ACSR	232,543	4,163,227	4,395,769					11
6-795 ACSR								12
6-795 ACSR	296,334	6,111,412	6,407,746					13
6-795 ACSR								14
6-795 ACSR	24,099	872,818	896,916					15
6-795 ACSR								16
6-954 ACSR	4,408,021	10,551,247	14,959,267					17
6-795 ACSR								18
6-795 ACSR	986,693	2,690,664	3,677,357					19
6-795 ACSR								20
6-795 ACSR	41,979	5,206,476	5,248,455					21
6-795 ACSR	35,037	4,307,001	4,342,038					22
6-795 ACSR	43,098	5,272,671	5,315,769					23
6-795 ACSR								24
6-795 ACSR	67,126	8,521,013	8,588,139					25
6-795 ACSR								26
6-954 ACSR								27
6-954 ACSR	868,700	14,270,807	15,139,507					28
6-954 ACSR								29
6-954 ACSR								30
6-954 ACSR	13,498	949,170	962,668					31
6-954 ACSR								32
6-795 ACSR	1,136,939	2,280,784	3,417,723					33
6-795 ACSR	1,136,938	2,189,075	3,326,013					34
6-795 ACSR								35
	126,838,425	2,092,665,186	2,219,503,600	1,248,687	8,132,482	3,498,285	12,879,454	36

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)	
6-795 ACSR	104,148	593,836	697,984					1
6-795 ACSR								2
6-795 ACSR	873,092	4,496,170	5,369,263					3
6-954 ACSR								4
6-795 ACSR								5
6-795 ACSR								6
6-795 ACSR	45,639	512,475	558,113					7
6-795 ACSR	1,296,677	6,960,661	8,257,338					8
6-795 ACSR								9
6-795 ACSR	401,128	2,587,137	2,988,265					10
6-795 ACSR								11
6-795 ACSR		888,655	888,655					12
6-954 ACSS/TW	5,233,602	10,969,295	16,202,897					13
6-954 ACSS/TW	124,881	22,345,458	22,470,338					14
6-954 ACSS/TW	543,359	20,993,906	21,537,264					15
6-954 ACSS/TW	191,273	34,225,322	34,416,594					16
6-795 ACSS	13,748	933,240	946,988					17
6-795 ACSS		1,215,849	1,215,849					18
6-556.5 ACSR/T2	3,526,999	59,521,087	63,048,085					19
6-954 ACSS/TW	5,172,751	59,228,208	64,400,959					20
6-954 ACSS/TW								21
6-397.5 TACSR/R	8,233,704	53,926,154	62,159,858					22
6-954 ACSS/TW	340,384	27,165,962	27,506,346					23
6-954 ACSS/TW	5,895,536	37,681,201	43,576,737					24
6-954 ACSS/TW	6,406,849	36,282,633	42,689,482					25
6-954 ACSS/TW								26
6-954 ACSS/TW	9,984,403	112,135,762	122,120,165					27
6-954 ACSS/TW								28
6-954 ACSS/TW	4,764,330	65,839,990	70,604,320					29
6-954 ACSS/TW	6,067,350	83,209,780	89,277,130					30
6-954 ACSS/TW								31
6-954 ACSS/TW	1,513,232	23,696,680	25,209,911					32
6-954 ACSS/TW	4,188,381	66,051,104	70,239,485					33
6-397.5 ACSR/T2	7,139,056	107,542,972	114,682,028					34
6-954 ACSS/TW								35
	126,838,425	2,092,665,186	2,219,503,600	1,248,687	8,132,482	3,498,285	12,879,454	36

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)	
6-954 ACSS/TW		4,114,844	4,114,844					1
6-954 ACSR	554,100	5,385,767	5,939,867					2
6-954 ACSS/TW								3
6-954 ACSS/TW	355,907	9,176,023	9,531,930					4
3-795 ACSS	884,508	9,194,724	10,079,232					5
3-795 ACSS	1,023,124	23,387,110	24,410,234					6
3-954 ACSR	44,582	437,305	481,887					7
3-954 ACSR	1,243,925	12,080,587	13,324,512					8
3-795 ACSR	302,577	7,615,686	7,918,263					9
3-795 ACSR								10
3-795 ACSS	531,676	605,867	1,137,542					11
3-954 ACSR	24,662	1,532,861	1,557,523					12
3-954 ACSR								13
3-795 ACSR	21,223	808,247	829,470					14
3-954 ACSR	57,281	2,812,304	2,869,586					15
3-954 ACSR								16
3-795 ACSR	10,733	237,425	248,158					17
3-795 ACSR	21,002	597,200	618,203					18
3-795 ACSR								19
3-795 ACSR	55,625	283,964	339,589					20
3-795 ACSR	57,863	7,763,724	7,821,587					21
3-795 ACSR								22
3-1272 ACSR	407,857	6,391,883	6,799,740					23
3-795 ACSR								24
3-1272 ACSR								25
3-795 ACSR	29,881	2,219,835	2,249,716					26
3-795 ACSR	371,590	5,225,716	5,597,306					27
3-795 ACSR								28
3-795 ACSR								29
3-795 ACSR	5,902	1,351,603	1,357,504					30
3-795 ACSR								31
3-795 ACSR	59,673	1,635,478	1,695,151					32
3-795 ACSS	1,323,879	9,559,156	10,883,035					33
6-397.5 TACSR/TW	636,147	12,371,059	13,007,206					34
6-954 ACSS/TW								35
	126,838,425	2,092,665,186	2,219,503,600	1,248,687	8,132,482	3,498,285	12,879,454	36

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 ACSS	477,246	6,134,098	6,611,344					1
3-795 ACSS	52,746	9,823,670	9,876,416					2
3000 kcmil CU								3
3-477 ACSR	16,110	546,227	562,337					4
3-477 ACSR	17,390	540,316	557,706					5
3-477 ACSR								6
3-477 ACSR	25,772	928,604	954,375					7
3-2312 ACSR								8
3-477 ACSR	143,079	1,706,835	1,849,914					9
3-565.3 ACSS/TW								10
								11
	23,390,702	622,041,630	645,432,333					12
								13
	5,681,443	238,354,077	244,035,519					14
								15
	436,068	29,206,664	29,642,732					16
								17
				1,248,687	8,132,482	3,498,285	12,879,454	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	126,838,425	2,092,665,186	2,219,503,600	1,248,687	8,132,482	3,498,285	12,879,454	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 1 Column: a

Overall data organization has been adjusted for 2017 FERC Form 1 reporting; now reporting by OPERATING CIRCUIT, previous year reports were organized by LINE NUMBER

Schedule Page: 422.2 Line No.: 13 Column: a

NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1000%(10.84 miles) of 30.04 miles of this line; remaining 63.9000%(19.20 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 14 Column: a

NSM ((0972-MN;01) BROOKINGS CO.-HAWKS NEST LAKE) : Xcel Energy owns 67.8174%(12.53 miles) of 18.48 miles of this line; remaining 32.1826%(05.95 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 15 Column: a

NSM ((0972-SD;01) BROOKINGS CO.-HAWKS NEST LAKE) : Xcel Energy owns 67.8174%(07.07 miles) of 10.42 miles of this line; remaining 32.1826%(03.35 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 16 Column: a

NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.8174%(20.72 miles) of 30.55 miles of this line; remaining 32.1826%(09.83 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 19 Column: a

NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0000%(35.79 miles) of 71.58 miles of this line; remaining 50.0000%(35.79 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 20 Column: a

NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(27.75 miles) of 43.36 miles of this line; remaining 36.0000%(15.61 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 22 Column: a

NSM ((0964;01) HAMPTON-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(24.22 miles) of 37.85 miles of this line; remaining 36.0000%(13.63 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 23 Column: a

NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8174%(16.64 miles) of 24.54 miles of this line; remaining 32.1826%(07.90 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 24 Column: a

NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8174%(12.27 miles) of 18.1 miles of this line; remaining 32.1826%(05.83 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 25 Column: a

NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8174%(14.15 miles) of 20.87 miles of this line; remaining 32.1826%(06.72 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 26 Column: a

NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8174%(49.55 miles) of 73.06 miles of this line; remaining 32.1826%(23.51 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 27 Column: a

NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8174%(49.57 miles) of 73.1 miles of this line; remaining 32.1826%(23.53 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 28 Column: a

NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8174%(33.56 miles) of 49.49 miles of this line; remaining 32.1826%(15.93 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 29 Column: a

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8174%(33.56 miles) of 49.49 miles of this line; remaining 32.1826%(15.93 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 30 Column: a

NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1000%(37.65 miles) of 104.29 miles of this line; remaining 63.9000%(66.64 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 32 Column: a

NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1000%(12.45 miles) of 34.49 miles of this line; remaining 63.9000%(22.04 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 33 Column: a

NSM ((0954;01) ALEXANDRIA SW. ST.-QUARRY) : Xcel Energy owns 36.1000%(29.32 miles) of 81.22 miles of this line; remaining 63.9000%(51.90 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 4 Column: a

NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8174%(03.37 miles) of 4.97 miles of this line; remaining 32.1826%(01.60 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 5 Column: a

NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 29.8962%(05.78 miles) of 19.32 miles of this line; remaining 70.1038%(13.54 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 6 Column: a

NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2000%(13.48 miles) of 51.46 miles of this line; remaining 73.8000%(37.98 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 33 Column: a

NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(09.93 miles) of 15.51 miles of this line; remaining 36.0000%(05.58 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 34 Column: a

NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(17.70 miles) of 27.66 miles of this line; remaining 36.0000%(09.96 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.4 Line No.: 12 Column: a

NSM ((5558;01) CEDAR MTN. (GRE)-FRANKLIN) : Xcel Energy owns 67.8174%(02.92 miles) of 4.3 miles of this line; remaining 32.1826%(01.38 miles) is owned by other members of the CapX2020 joint venture

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 completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	71.58	SINGLE POLE	5.00	1	1
2	(5300;01) HUNTLEY (ITC)	SOUTH BEND	1.41	SINGLE POLE	8.00	1	1
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							
41							
42							
43							
44	TOTAL		72.99		13.00	2	2

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)	
6-556.5	ACSR/T2	26/7	345	3,526,999	39,215,468	20,305,619		63,048,086	1
3-565.3	ACSS/TW		161	143,079	1,212,685	494,151		1,849,915	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
									41
									42
									43
				3,670,078	40,428,153	20,799,770		64,898,001	44

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
FOOTNOTE DATA			

Schedule Page: 424 Line No.: 1 Column: a
NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0000%(35.79 miles) of 71.58 miles of this line; remaining 50.0000%(35.79 miles) is owned by other members of the CapX2020 joint venture.

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	A.S.KING-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
2	ADAMS-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
3	ADA-TR01	UNATTENDED DISTRIB	69.00	23.00	4.16
4	AFTON-TR01	UNATTENDED DISTRIB	115.00	34.50	
5	AFTON-TR02	UNATTENDED DISTRIB	115.00	34.50	
6	AIR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	AIR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	AIRPORT-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	AIRPORT-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	ALBANY-TR02	UNATTENDED DISTRIB	69.00	12.50	
11	ALBANY-TR03	UNATTENDED DISTRIB	12.50	4.16	
12	ALDRICH-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	ALDRICH-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	ALDRICH-TR04	UNATTENDED DISTRIB	115.00	13.80	
15	ALEXANDRIA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	4.16	
16	ALTURA-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	ANNANDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	APACHE-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	APACHE-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	ARDEN HILLS-TR01	UNATTENDED TRANSM	115.00	69.00	13.80
21	ARDEN HILLS-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
22	ARLINGTON-TR01	UNATTENDED DISTRIB	69.00	4.16	
23	ATWATER-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	AVERILL-TR01	UNATTENDED DISTRIB	69.00	23.00	4.00
25	AVON-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	BASSETT CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	BASSETT CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	BATTLE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	BATTLE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	BAYTOWN-TR01	UNATTENDED DISTRIB	118.00	13.80	
31	BECKER-TR01	UNATTENDED DISTRIB	69.00	12.50	
32	BECKER-TR02	UNATTENDED DISTRIB	69.00	34.50	
33	BELGRADE-TR01	UNATTENDED DISTRIB	69.00	4.16	
34	BELLE PLAINE-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	BIRCH-TR01	UNATTENDED DISTRIB	69.00	34.50	
36	BIRD ISLAND-TR02	UNATTENDED DISTRIB	69.00	4.16	
37	BLUE HERON-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	BLUE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	BLUE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	BLUE LAKE-TR07	UNATTENDED TRANSM	230.00	115.00	13.80

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	BLUE LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	13.80
2	BLUFF CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	BLUFF CREEK-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
4	BROOKINGS COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
5	BROOKINGS COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	13.80
6	BROOKLYN PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	BROOKLYN PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	BROOK-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	4.16	
9	BROOTEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	BROWNTON-TR01	UNATTENDED DISTRIB	69.00	2.40	
11	BUFFALO LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	BUFFALO RIDGE-TR01	UNATTENDED DISTRIB	115.00	34.50	13.80
13	BUFFALO RIDGE-TR02	UNATTENDED DISTRIB	115.00	34.50	13.80
14	BURNSIDE-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	BURNSIDE-TR02	UNATTENDED DISTRIB	69.00	12.50	
16	BUTTERFIELD-TR01	UNATTENDED DISTRIB	69.00	4.16	
17	CANISTOTA JUNCTION-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	CANISTOTA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	4.16	
19	CANNON FALLS TRANS-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
20	CANNON FALLS TRANS-TR07	UNATTENDED TRANSM	115.00	69.00	13.80
21	CANNON FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	CANOVA-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
23	CANTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	CANTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
25	CARVER COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	35.00
26	CARVER COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	35.00
27	CASS COUNTY-TR01X,TR01Y	UNATTENDED DISTRIB	115.00	23.00	3.00
28	CASS COUNTY-TR02	UNATTENDED DISTRIB	115.00	23.00	
29	CASS COUNTY-TR03	UNATTENDED DISTRIB	115.00	23.00	14.00
30	CASTLE ROCK-TR01	UNATTENDED DISTRIB	69.00	4.00	
31	CEDAR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	CEDAR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	CEDARVALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	CEDARVALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	CENTERVILLE-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	CHANARAMBIE-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
37	CHANARAMBIE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
38	CHANARAMBIE-TR04	UNATTENDED DISTRIB	115.00	34.50	14.00
39	CHEMOLITE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	CHEMOLITE-TR02	UNATTENDED DISTRIB	115.00	13.80	

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	CHERRY CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	CHERRY CREEK-TR03	UNATTENDED DISTRIB	115.00	34.50	
3	CHISAGO COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	
4	CHISAGO COUNTY-TR05	UNATTENDED TRANSM	345.00	115.00	35.00
5	CHISAGO COUNTY-TR06	UNATTENDED TRANSM	345.00	115.00	35.00
6	CHISAGO COUNTY-TR09A,TR09B,TR09C	UNATTENDED TRANSM	500.00	345.00	35.00
7	CHISAGO COUNTY-TR10SA,TR10B,TR10C	UNATTENDED TRANSM	500.00	345.00	35.00
8	CLARA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	CLARA CITY-TR02	UNATTENDED DISTRIB	69.00	23.00	
10	CLARKS GROVE-TR01	UNATTENDED DISTRIB	69.00	7.20	
11	CLIFF AVENUE-TR01	UNATTENDED DISTRIB	69.00	4.16	
12	CLIFF AVENUE-TR02	UNATTENDED DISTRIB	69.00	13.80	
13	COKATO-TR01	UNATTENDED DISTRIB	69.00	13.80	
14	COLVILL-TR04	UNATTENDED TRANSM	115.00	69.00	14.00
15	COLVILL-TR05	UNATTENDED TRANSM	161.00	115.00	14.00
16	COON CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	COON CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	COON CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
19	COON CREEK-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
20	COTTAGE GROVE-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	COTTAGE GROVE-TR02	UNATTENDED DISTRIB	115.00	13.80	
22	CREDIT RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	CREDIT RIVER-TR02	UNATTENDED DISTRIB	69.00	12.50	
24	CROOKED LAKE-TR01	UNATTENDED DISTRIB	119.00	13.80	
25	CROOKED LAKE-TR02	UNATTENDED DISTRIB	119.00	13.80	
26	CROOKED LAKE-TR03	UNATTENDED DISTRIB	115.00	12.50	
27	CROOKED LAKE-TR65A,TR65B,TR65C	UNATTENDED DISTRIB	13.80	12.50	
28	CROSSROADS-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	CROSSROADS-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	CROSSROADS-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	CRYSTAL FOODS-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	DAHLGREN-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	DANUBE-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	DASSEL-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	DAYTONS BLUFF-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	DAYTONS BLUFF-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	DAYTONS BLUFF-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	DEEPHAVEN-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	DEEPHAVEN-TR02	UNATTENDED DISTRIB	69.00	13.80	
40	DELANO-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	7.20	

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	DELL RAPIDS-TR02	UNATTENDED DISTRIB	34.50	12.50	
2	DODGE CENTER-TR01	UNATTENDED DISTRIB	69.00	23.00	
3	DODGE CENTER-TR02	UNATTENDED DISTRIB	69.00	12.50	
4	DODGE CENTER-TR03	UNATTENDED DISTRIB	69.00	12.50	
5	DOVE PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
6	DOUGLAS COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	35.00
7	DOUGLAS COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
8	DOUGLAS COUNTY-TR03	UNATTENDED DISTRIB	69.00	13.80	
9	DUNDAS-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	DUNDAS-TR02	UNATTENDED DISTRIB	69.00	13.80	
11	EAGLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	EAST BLOOMINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	EAST BLOOMINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	EAST BLOOMINGTON-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	EAST WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	EASTWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	EASTWOOD-TR02	UNATTENDED DISTRIB	69.00	13.80	
18	EASTWOOD-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	ECHO-TR01	UNATTENDED DISTRIB	23.00	4.16	
20	EDEN PRAIRIE-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	EDEN PRAIRIE-TR03	UNATTENDED DISTRIB	115.00	13.80	
22	EDEN PRAIRIE-TR04	UNATTENDED DISTRIB	115.00	13.80	
23	EDEN PRAIRIE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
24	EDEN PRAIRIE-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
25	EDGERTON-TR01	UNATTENDED DISTRIB	23.00	4.16	
26	EDINA-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	EDINA-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	EDINA-TR03	UNATTENDED DISTRIB	115.00	13.80	
29	ELLIOT PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	ELLIOT PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	ELLIOT PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
32	ELM CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	ELM CREEK-TR02	UNATTENDED DISTRIB	115.00	34.50	
34	ELM CREEK-TR03	UNATTENDED DISTRIB	115.00	13.80	
35	ELM CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
36	EMERY-TR01A,TR01B,TR01CC	UNATTENDED DISTRIB	34.50	4.16	
37	ESSIG-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	2.40	
38	EXCELSIOR-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	FAIR PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
40	FAIR PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	

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	FALLS-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	FALLS-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	FARIBAULT-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	FARIBAULT-TR02	UNATTENDED DISTRIB	69.00	13.80	
5	FARMINGTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
6	FARMINGTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
7	FENTON-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
8	FENTON-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
9	FENTON-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
10	FIESTA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	FIESTA CITY-TR02	UNATTENDED DISTRIB	69.00	12.50	
12	FIFTH STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	FIFTH STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	FIFTH STREET-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	FIFTH STREET-TR04	UNATTENDED DISTRIB	115.00	13.80	
16	FIRST LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
17	FOLEY-TR01	UNATTENDED DISTRIB	34.50	4.16	
18	FORBES-TR09	UNATTENDED DISTRIB	500.00	20.00	
19	FORT RIDGLEY-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
20	FRANKLIN-TR04	UNATTENDED DISTRIB	69.00	23.00	
21	FRANKLIN-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
22	FRANKLIN-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
23	FRANKLIN-TR07	UNATTENDED DISTRIB	69.00	4.16	
24	FRONTENAC-TR01	UNATTENDED DISTRIB	69.00	12.50	
25	GATEWAY-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	GATEWAY-TR02	UNATTENDED DISTRIB	69.00	12.50	
27	GAYLORD-TR01	UNATTENDED DISTRIB	69.00	4.00	
28	GIBBON-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	GLEASON LAKE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
30	GLEASON LAKE-TR03	UNATTENDED DISTRIB	34.50	13.80	
31	GLEASON LAKE-TR04	UNATTENDED DISTRIB	115.00	34.50	
32	GLEASON LAKE-TR07	UNATTENDED DISTRIB	115.00	13.80	
33	GLEASON LAKE-TR08	UNATTENDED DISTRIB	115.00	13.80	
34	GLEN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	GLEN LAKE-TR02	UNATTENDED DISTRIB	69.00	13.80	
36	GLENWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	GLENWOOD-TR02	UNATTENDED DISTRIB	69.00	12.50	
38	GOODVIEW-TR01	UNATTENDED DISTRIB	69.00	12.50	
39	GOODVIEW-TR02	UNATTENDED DISTRIB	69.00	12.50	
40	GOOSE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	

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	GOOSE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	GOPHER-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	GOPHER-TR02	UNATTENDED DISTRIB	115.00	13.80	
4	GRANITE CITY-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	GRANITE CITY-TR02	UNATTENDED DISTRIB	115.00	13.80	
6	GRANITE CITY-TR03	UNATTENDED DISTRIB	115.00	34.50	
7	GRANT-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
8	GRANT-TR03	UNATTENDED DISTRIB	115.00	34.50	
9	GREEN ISLE-TR01	UNATTENDED DISTRIB	69.00	4.16	
10	GREENFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	HADLEY-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	HASSAN-TR01	UNATTENDED DISTRIB	115.00	34.50	
13	HASSAN-TR02	UNATTENDED DISTRIB	115.00	34.50	
14	HASTINGS-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	HASTINGS-TR02	UNATTENDED DISTRIB	69.00	12.50	
16	HATFIELD-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	23.00	12.50	
17	HATTON-TR01	UNATTENDED DISTRIB	69.00	4.16	
18	HAZEL CREEK-TR09	UNATTENDED TRANSM	345.00	230.00	14.00
19	HECTOR-TR01	UNATTENDED DISTRIB	69.00	4.16	
20	HENDERSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
21	HIAWATHA WEST-TR01	UNATTENDED DISTRIB	115.00	13.80	
22	HIGH BRIDGE-TR04	UNATTENDED DISTRIB	115.00	13.80	
23	HOLLYDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	HOLLYDALE-TR02	UNATTENDED DISTRIB	34.50	13.80	
25	HOWARD JUNCTION-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	34.50	12.50	
26	HOWARD LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
27	HUGO-TR01	UNATTENDED DISTRIB	115.00	34.50	
28	HUGO-TR02	UNATTENDED DISTRIB	115.00	34.50	
29	HYLAND LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	HYLAND LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	INDIANA-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	INDIANA-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	INDUSTRIAL-TR01	UNATTENDED DISTRIB	34.50	4.16	
34	INDUSTRIAL-TR02	UNATTENDED DISTRIB	34.50	4.16	
35	INVER GROVE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
36	INVER GROVE-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
37	INVER HILLS-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
38	INVER HILLS-PLTSDU	UNATTENDED DISTRIB	34.50	13.80	
39	JORDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
40	KASSON-TR01	UNATTENDED DISTRIB	69.00	12.50	

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	KASSON-TR02	UNATTENDED DISTRIB	69.00	12.50	
2	KEGAN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
3	KENYON-TR01	UNATTENDED DISTRIB	69.00	12.50	
4	KIMBALL-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	KOCH REFINERY-TR11	UNATTENDED DISTRIB	115.00	13.80	
6	KOCH REFINERY-TR12	UNATTENDED DISTRIB	115.00	13.80	
7	KOCH REFINERY-TR13	UNATTENDED DISTRIB	115.00	13.80	
8	KOCH REFINERY-TR14	UNATTENDED DISTRIB	115.00	13.80	
9	KOCH REFINERY-TR15	UNATTENDED DISTRIB	115.00	13.80	
10	KOCH REFINERY-TR16	UNATTENDED DISTRIB	115.00	13.80	
11	KOHLMAN LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	KOHLMAN LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	KOHLMAN LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
14	KOHLMAN LAKE-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
15	LA CRESENT-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	LAFAYETTE-TR01	UNATTENDED DISTRIB	69.00	4.16	
17	LAKE BAVARIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
18	LAKE EMILY-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	LAKE LILAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	LAKE PULASKI-TR03	UNATTENDED DISTRIB	115.00	34.50	
21	LAKE PULASKI-TR05	UNATTENDED TRANSM	115.00	69.00	35.00
22	LAKE PULASKI-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
23	LAKE YANKTON-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
24	LAKE YANKTON-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
25	LAKE YANKTON-TR03	UNATTENDED DISTRIB	69.00	13.80	
26	LARIMORE-TR01	UNATTENDED DISTRIB	69.00	4.16	
27	LAWRENCE CREEK-TR01	UNATTENDED DISTRIB	115.00	34.50	
28	LAWRENCE CREEK-TR04	UNATTENDED TRANSM	115.00	69.00	14.00
29	LAWRENCE CREEK-TR05	UNATTENDED TRANSM	161.00	115.00	14.00
30	LAWRENCE-TR01	UNATTENDED DISTRIB	115.00	34.50	
31	LAWRENCE-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
32	LAWRENCE-TR08	UNATTENDED TRANSM	115.00	69.00	14.00
33	LENNOX-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	LESTER PRAIRIE-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	LEXINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	LEXINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	LEXINGTON-TR03	UNATTENDED DISTRIB	115.00	34.50	
38	LEXINGTON-TR04	UNATTENDED DISTRIB	34.50	13.80	
39	LINCOLN CO-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
40	LINCOLN CO-TR07	UNATTENDED DISTRIB	115.00	13.80	

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	LINCOLN CO-TR08	UNATTENDED DISTRIB	115.00	13.80	
2	LINDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	LINDSTROM-TR01	UNATTENDED DISTRIB	115.00	12.50	
4	LINDSTROM-TR02	UNATTENDED DISTRIB	115.00	12.50	
5	LINN STREET-TR01	UNATTENDED DISTRIB	69.00	12.50	
6	LINN STREET-TR02	UNATTENDED DISTRIB	69.00	12.50	
7	LONE OAK-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	LONE OAK-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	LONG LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
10	LONG LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
11	LOUISE-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	LOWRY-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	LYON COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
14	LYON COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
15	M E INTERNATIONAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	M E INTERNATIONAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	MAIN STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	MAIN STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	MAPLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	MAPLE RIVER-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
21	MAPLE RIVER-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
22	MAPLETON-TR01	UNATTENDED DISTRIB	69.00	13.80	
23	MARION-TR01	UNATTENDED DISTRIB	23.00	4.16	
24	MAXWELL-TR01	UNATTENDED DISTRIB	115.00	4.16	
25	MAYHEW LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
26	MAYNARD (TRANSMISSION STATION)-TR01	UNATTENDED TRANSM	115.00	69.00	
27	MAYNARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
28	MAYVILLE-TR01	UNATTENDED DISTRIB	69.00	4.16	
29	MAYVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
30	MAZEPPA-TR01	UNATTENDED DISTRIB	69.00	12.50	
31	MEDFORD JCT-TR01	UNATTENDED DISTRIB	69.00	12.50	
32	MEDICINE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	MEDICINE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
34	MEDICINE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
35	MEIRE GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
36	MERIDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
37	MERRIAM PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	MERRIAM PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
39	MERRIAM PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
40	MIDTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	

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	MINNEHAHA-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	MINNEHAHA-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	MINNESOTA LAKE-TR01	UNATTENDED DISTRIB	69.00	4.16	
4	MINNESOTA PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
5	MINNESOTA VALLEY-TR02	UNATTENDED DISTRIB	69.00	23.00	
6	MINNESOTA VALLEY-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
7	MINNESOTA VALLEY-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
8	MINNESOTA VALLEY-TR11	UNATTENDED TRANSM	115.00	69.00	14.00
9	MINNESOTA VALLEY-TR12	UNATTENDED TRANSM	115.00	69.00	14.00
10	MONTEVIDEO-TR01	UNATTENDED DISTRIB	69.00	4.16	
11	MONTEVIDEO-TR02	UNATTENDED DISTRIB	69.00	12.50	
12	MONTICELLO-TR06	UNATTENDED TRANSM	345.00	230.00	14.00
13	MONTICELLO-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
14	MONTROSE-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	MOORE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	MOORE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	MOORE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
18	MORGAN-TR01	UNATTENDED DISTRIB	69.00	23.00	
19	MORRISTOWN-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	MOUND-TR01	UNATTENDED DISTRIB	69.00	13.80	
21	MOUND-TR02	UNATTENDED DISTRIB	69.00	13.80	
22	NERSTRAND-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	12.50	
23	NINE MILE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
24	NINE MILE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
25	NOBLES COUNTY-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
26	NOBLES COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
27	NOBLES COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
28	NOBLES COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
29	NORDIC-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	NORDIC-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	NORTH BROADWAY-TR01	UNATTENDED DISTRIB	23.00	4.16	
32	NORTH BROADWAY-TR02	UNATTENDED DISTRIB	23.00	4.16	
33	NORTH ROCHESTER-TR09	UNATTENDED TRANSM	345.00	161.00	35.00
34	NORTH STAR STEEL-TR01	UNATTENDED DISTRIB	115.00	13.80	
35	NORTH STAR STEEL-TR02	UNATTENDED DISTRIB	115.00	13.80	
36	NORTH STAR STEEL-TR03	UNATTENDED DISTRIB	115.00	13.80	
37	NORTHFIELD-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	NORTHFIELD-TR02	UNATTENDED DISTRIB	69.00	13.80	
39	OAK PARK-TR01	UNATTENDED DISTRIB	115.00	23.00	14.00
40	OAK PARK-TR07	UNATTENDED DISTRIB	115.00	13.80	

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	OAK PARK-TR08	UNATTENDED DISTRIB	115.00	13.80	
2	OAKDALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	OAKDALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
4	ORONO-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	OSSEO-TR01	UNATTENDED DISTRIB	115.00	13.80	
6	OSSEO-TR02	UNATTENDED DISTRIB	115.00	13.80	
7	PARKERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	PARKERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	PARKERS LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
10	PARKERS LAKE-TR09A,TR09B,TR09C	UNATTENDED TRANSM	345.00	115.00	14.00
11	PARKERS LAKE-TR10A,TR10B,TR10C	UNATTENDED TRANSM	345.00	115.00	14.00
12	PAYNESVILLE XMSN-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
13	PAYNESVILLE XMSN-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
14	PAYNESVILLE XMSN-TR04	UNATTENDED DISTRIB	115.00	34.50	
15	PAYNESVILLE XMSN-TR09	UNATTENDED TRANSM	230.00	115.00	14.00
16	PINE BEND-TR03	UNATTENDED DISTRIB	69.00	13.80	
17	PINE ISLAND-TR01	UNATTENDED DISTRIB	69.00	12.50	
18	PINE ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
19	PIPESTONE-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	PIPESTONE-TR02	UNATTENDED DISTRIB	69.00	4.16	
21	PIPESTONE-TR03	UNATTENDED DISTRIB	69.00	25.00	
22	PIPESTONE-TR05	UNATTENDED TRANSM	115.00	69.00	3.00
23	PIPESTONE-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
24	PLATO-TR01	UNATTENDED DISTRIB	115.00	12.50	
25	PRAIRIE ISLAND-TR10	UNATTENDED TRANSM	345.00	161.00	14.00
26	PRAIRIE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
27	PRAIRIE-TR03	UNATTENDED TRANSM	115.00	69.00	14.00
28	PRAIRIE-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
29	PRAIRIE-TR07	UNATTENDED TRANSM	230.00	115.00	14.00
30	PRAIRIE-TR08	UNATTENDED TRANSM	230.00	115.00	14.00
31	PRIOR-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	QUARRY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
33	RAMSEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	RAMSEY-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	RAPIDAN-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	RED RIVER-TR01	UNATTENDED DISTRIB	115.00	23.00	14.00
37	RED RIVER-TR02	UNATTENDED DISTRIB	115.00	23.00	14.00
38	RED RIVER-TR03	UNATTENDED DISTRIB	115.00	23.00	5.00
39	RED ROCK-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	RED ROCK-TR02	UNATTENDED DISTRIB	115.00	13.80	

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	RED ROCK-TR03	UNATTENDED DISTRIB	115.00	13.80	
2	RED ROCK-TR05	UNATTENDED TRANSM	345.00	230.00	14.00
3	RED ROCK-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
4	RED ROCK-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
5	RED WING-TR01	UNATTENDED DISTRIB	69.00	13.80	
6	RED WING-TR02	UNATTENDED DISTRIB	69.00	13.80	
7	RENVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	REYNOLDS-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	RICH SPRING-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	RICH VALLEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	RICHMOND-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	RIVERSIDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	RIVERSIDE-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	RIVERWOOD-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	RIVERWOOD-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	ROCK RIVER-TR01	UNATTENDED DISTRIB	69.00	23.00	
17	ROGERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	ROGERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	ROSE PLACE-TR01	UNATTENDED DISTRIB	115.00	13.80	
20	ROSE PLACE-TR02	UNATTENDED DISTRIB	115.00	13.80	
21	ROSEMOUNT-TR01	UNATTENDED DISTRIB	115.00	34.50	
22	SACRED HEART-TR01	UNATTENDED DISTRIB	69.00	13.80	4.00
23	SALEM-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	34.50	3.00
24	SALEM-TR02	UNATTENDED DISTRIB	69.00	13.80	
25	SALIDA CROSSING-TR01	UNATTENDED DISTRIB	115.00	13.80	
26	SARTELL-TR01	UNATTENDED DISTRIB	34.50	12.50	2.00
27	SAUK RIVER-TR01	UNATTENDED DISTRIB	115.00	34.50	
28	SAVAGE-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	SAVAGE-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	SCANDIA-TR01	UNATTENDED DISTRIB	69.00	12.50	
31	SCOTT COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
32	SCOTT COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
33	SCOTT COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
34	SCOTT COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
35	SEDAN-TR01	UNATTENDED DISTRIB	69.00	7.20	
36	SHEAS LAKE-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
37	SHEAS LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
38	SHEPARD-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	SHEPARD-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	SHERCO-TR09	UNATTENDED TRANSM	345.00	115.00	14.00

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	SHEYENNE-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
2	SHEYENNE-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
3	SIBLEY PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	SIBLEY PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	
5	SIOUX FALLS-TR07	UNATTENDED DISTRIB	69.00	13.80	
6	SIOUX FALLS-TR08	UNATTENDED DISTRIB	69.00	13.80	
7	SLAYTON WEST-TR01	UNATTENDED DISTRIB	69.00	13.80	
8	SOURIS-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	SOURIS-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	SOURIS-TR03	UNATTENDED DISTRIB	115.00	13.80	
11	SOUTH BEND-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
12	SOUTH BEND-TR06	UNATTENDED TRANSM	161.00	115.00	14.00
13	SOUTH HAVEN-TR01	UNATTENDED DISTRIB	69.00	34.50	
14	SOUTH RENNER-TR01	UNATTENDED DISTRIB	115.00	34.50	
15	SOUTH RIDGE-TR01	UNATTENDED DISTRIB	69.00	23.00	
16	SOUTH SIOUX FALLS-TR03	UNATTENDED DISTRIB	69.00	13.80	
17	SOUTH SIOUX FALLS-TR04	UNATTENDED DISTRIB	69.00	13.80	
18	SOUTHTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	SOUTHTOWN-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	SOUTHTOWN-TR03	UNATTENDED DISTRIB	115.00	13.80	
21	SOUTH-TR01A,TR01B,TR01C	UNATTENDED DISTRIB	69.00	2.40	
22	SPLIT ROCK-TR06	UNATTENDED TRANSM	161.00	115.00	35.00
23	SPLIT ROCK-TR07	UNATTENDED TRANSM	230.00	115.00	14.00
24	SPLIT ROCK-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
25	SPLIT ROCK-TR11	UNATTENDED TRANSM	345.00	115.00	14.00
26	ST. CLAIRE-TR01	UNATTENDED DISTRIB	13.20	4.16	
27	ST. CLAIRE-TR02	UNATTENDED DISTRIB	13.20	4.16	
28	ST. CLOUD-TR01	UNATTENDED DISTRIB	115.00	34.50	
29	ST. CLOUD-TR02	UNATTENDED DISTRIB	115.00	34.50	
30	ST JAMES-TR01	UNATTENDED DISTRIB	69.00	12.50	
31	ST JOHNS-TR01	UNATTENDED DISTRIB	69.00	4.16	
32	ST. JOSEPH-TR01	UNATTENDED DISTRIB	69.00	4.16	
33	ST. LOUIS PARK-TR02	UNATTENDED DISTRIB	115.00	34.50	
34	ST. LOUIS PARK-TR04	UNATTENDED DISTRIB	115.00	13.80	
35	ST. LOUIS PARK-TR05	UNATTENDED DISTRIB	115.00	13.80	
36	ST. LOUIS PARK-TR06	UNATTENDED DISTRIB	115.00	13.80	
37	STEWART-TR01	UNATTENDED DISTRIB	69.00	12.50	
38	STOCKYARDS-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	STOCKYARDS-TR02	UNATTENDED DISTRIB	118.00	13.80	
40	SUMMIT AVENUE-TR01	UNATTENDED DISTRIB	115.00	13.80	

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	SUMMIT AVENUE-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	SWAN LAKE-TR01	UNATTENDED DISTRIB	115.00	12.50	
3	TANNERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	TANNERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
5	TANNERS LAKE-TR23A1,TR23B1,TR23C1	UNATTENDED DISTRIB	13.80	12.50	
6	TANNERS LAKE-TR23A2,TR23B2,TR23C2	UNATTENDED DISTRIB	13.80	12.50	
7	TANNERS LAKE-TR32A1,TR32B1,TR32C1	UNATTENDED DISTRIB	13.80	12.50	
8	TANNERS LAKE-TR32A2,TR32B2,TR32C2	UNATTENDED DISTRIB	13.80	12.50	
9	TANNERS LAKE-TR34A1,TR34B1,TR34C1	UNATTENDED DISTRIB	13.80	12.50	
10	TANNERS LAKE-TR34A2,TR34B2,TR34C2	UNATTENDED DISTRIB	13.80	12.50	
11	TERMINAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	TERMINAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	TERMINAL-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	TERMINAL-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
15	TERMINAL-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
16	THOMPSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	TRACY SW STA-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	TRACY-TR01	UNATTENDED DISTRIB	69.00	4.16	2.00
19	TWIN LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
20	TWIN LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
21	TWIN LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
22	UPPER LEVEE-TR01	UNATTENDED DISTRIB	115.00	13.80	
23	UPPER LEVEE-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	UPPER LEVEE-TR03	UNATTENDED DISTRIB	115.00	13.80	
25	VERMILLION RIVER-TR03	UNATTENDED DISTRIB	115.00	13.80	
26	VESELI-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	VIKING-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	VILLARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	WABASHA-TR01	UNATTENDED DISTRIB	69.00	13.80	
30	WABASHA-TR02	UNATTENDED DISTRIB	69.00	2.40	
31	WACONIA-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	WAKEFIELD-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
33	WAKEFIELD-TR02A,TR02B,TR02C	UNATTENDED DISTRIB	34.50	13.80	
34	WAKEFIELD-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
35	WASECA-TR02	UNATTENDED DISTRIB	69.00	23.00	
36	WASECA-TR03	UNATTENDED DISTRIB	69.00	23.00	
37	WASECA-TR04	UNATTENDED DISTRIB	69.00	23.00	
38	WATAB RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
39	WATERTOWN-TR01	UNATTENDED DISTRIB	69.00	13.80	
40	WATERVILLE-TR01	UNATTENDED DISTRIB	69.00	23.00	

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	WATERVILLE-TR02	UNATTENDED DISTRIB	69.00	4.16	
2	WATERVILLE-TR03	UNATTENDED DISTRIB	69.00	12.50	
3	WATKINS-TR01	UNATTENDED DISTRIB	69.00	4.16	
4	WAVERLY-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	WELLS CREEK-TR01	UNATTENDED DISTRIB	69.00	12.50	
6	WESCOTT NATURAL GAS-TR01	UNATTENDED DISTRIB	69.00	13.80	
7	WEST BYRON-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	WEST COON RAPIDS-TR01	UNATTENDED DISTRIB	115.00	34.50	
9	WEST COON RAPIDS-TR02	UNATTENDED DISTRIB	115.00	34.50	
10	WEST COON RAPIDS-TR03	UNATTENDED DISTRIB	34.50	13.80	
11	WEST FARIBAULT-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
12	WEST FARIBAULT-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
13	WEST FARIBAULT-TR03	UNATTENDED DISTRIB	69.00	13.80	
14	WEST FARIBAULT-TR07	UNATTENDED DISTRIB	69.00	13.80	
15	WEST HASTINGS-TR01	UNATTENDED DISTRIB	115.00	12.50	
16	WEST HASTINGS-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
17	WEST NEW ULM-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
18	WEST RIVER RD-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	WEST RIVER RD-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	WEST RIVER RD-TR03	UNATTENDED DISTRIB	115.00	13.80	
21	WEST SIOUX FALLS-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
22	WEST SIOUX FALLS-TR07	UNATTENDED DISTRIB	115.00	13.80	
23	WEST SIOUX FALLS-TR08	UNATTENDED DISTRIB	115.00	13.80	
24	WEST WACONIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	WEST WACONIA-TR02	UNATTENDED DISTRIB	115.00	34.50	
26	WESTERN-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	WESTERN-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	WESTGATE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
29	WESTGATE-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
30	WESTGATE-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	WESTGATE-TR04	UNATTENDED DISTRIB	115.00	13.80	
32	WESTGATE-TR05	UNATTENDED DISTRIB	115.00	34.50	
33	WESTGATE-TR06	UNATTENDED DISTRIB	115.00	34.50	
34	WESTPORT-TR01X,TR01Y	UNATTENDED DISTRIB	69.00	7.20	
35	WILLIAMS BROS PIPE-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	WILLIAMS BROS PIPE-TR02	UNATTENDED DISTRIB	13.80	2.40	
37	WILLIAMS BROS PIPE-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	WILMARTH-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
39	WILMARTH-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
40	WILMARTH-TR08	UNATTENDED TRANSM	115.00	69.00	14.00

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	WILMARTH-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
2	WILMARTH-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
3	WILSON-TR03	UNATTENDED DISTRIB	115.00	13.80	
4	WILSON-TR04	UNATTENDED DISTRIB	115.00	13.80	
5	WILSON-TR05	UNATTENDED DISTRIB	115.00	13.80	
6	WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
7	WINONA-TR02	UNATTENDED DISTRIB	69.00	13.80	
8	WINONA-TR03	UNATTENDED DISTRIB	69.00	13.80	
9	WINSTED-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	WINTHROP-TR01	UNATTENDED DISTRIB	69.00	4.16	
11	WOBEGON TRAIL-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	WOODBURY-TR01	UNATTENDED DISTRIB	115.00	34.50	
13	WOODBURY-TR02	UNATTENDED DISTRIB	115.00	34.50	
14	WYOMING-TR01	UNATTENDED DISTRIB	115.00	12.50	
15	WYOMING-TR02	UNATTENDED DISTRIB	115.00	12.50	
16	YANKEE-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
17	YANKEE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
18	YELLOW MEDICINE-TR01	UNATTENDED DISTRIB	69.00	23.00	
19	YOUNG AMERICA-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	YOUNG AMERICA-TR02	UNATTENDED DISTRIB	69.00	13.80	
21	ZUMBRO FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
22	ZUMBROTA-TR01	UNATTENDED DISTRIB	69.00	13.80	
23					
24	Count TTL Transformer Banks	582.0			
25	Count TTL Transformers In Service	630.0			
26	TTL MVA In Service	44,906.1			
27	Count TTL Substations with Transformers	311.0			
28	Count TTL Substations without Transformer	38.0			
29	Count TTL Substations	349.0			
30	Count TTL Spares	43.0			
31					
32	Spare Transformers				
33					
34	Canistota Junc	N/A	25.00	13.00	
35	Canistota Junc	N/A	25.00	5.00	
36	Chanarambie	N/A	115.00	35.00	14.00
37	Clarks Grove	N/A	69.00	7.50	
38	Falls Sub	N/A	69.00	14.00	
39	Falls Sub	N/A	69.00	14.00	
40	Hugo Trg Ctr	N/A	115.00	14.00	

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	Linde	N/A	115.00	14.00	
2	Maple Grove	N/A	345.00	161.00	14.00
3	Maple Grove	N/A	345.00	115.00	35.00
4	Maple Grove	N/A	345.00	115.00	35.00
5	Maple Grove	N/A	230.00	115.00	14.00
6	Maple Grove	N/A	161.00	115.00	14.00
7	Maple Grove	N/A	115.00	69.00	13.00
8	Maple Grove	N/A	115.00	69.00	14.00
9	Maple Grove	N/A	115.00	35.00	
10	Maple Grove	N/A	115.00	14.00	
11	Maple Grove	N/A	115.00	14.00	
12	Maple Grove	N/A	115.00	14.00	
13	Maple Grove	N/A	115.00	14.00	
14	Maple Grove	N/A	115.00	14.00	
15	Maple Grove	N/A	115.00	14.00	
16	Maple Grove	N/A	69.00	14.00	
17	Maple Grove	N/A	69.00	14.00	
18	Maple Grove	N/A	69.00	14.00	
19	Maple Grove	N/A	69.00	14.00	
20	Maple Grove	N/A	69.00	14.00	
21	Maple Grove	N/A	69.00	14.00	
22	Maple Grove	N/A	69.00	5.00	
23	Maple Grove	N/A	14.00	5.00	
24	Minn Valley	N/A	230.00	115.00	15.00
25	Minn Valley	N/A	230.00	115.00	15.00
26	Minn Valley	N/A	230.00	115.00	15.00
27	Minn Valley	N/A	69.00	25.00	2.50
28	Minn Valley	N/A	69.00	14.00	2.50
29	Paynsville Transmission	N/A	115.00	69.00	13.00
30	Paynsville Transmission	N/A	115.00	69.00	13.00
31	Portal Pipeline (Minot)	N/A	14.00	5.00	
32	Portal Pipeline (Minot)	N/A	14.00	2.50	
33	Prairie Island	N/A	345.00	25.00	2.50
34	Red River	N/A	115.00	25.00	
35	SPX-Wakasha	N/A	115.00	13.00	
36	SPX-Wakasha	N/A	69.00	14.00	
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
448	1					1
300	1					2
14	1					3
70	1					4
70	1					5
25	1					6
25	1					7
47	1					8
47	1					9
11	1					10
6	1					11
70	1					12
70	1					13
70	1					14
2	3					15
7	1					16
14	1					17
70	1					18
70	1					19
70	1					20
70	1					21
6	1					22
14	1					23
14	1					24
14	1					25
28	1					26
25	1					27
48	1					28
48	1					29
28	1					30
7	1					31
5	1					32
4	1					33
14	1					34
14	1					35
3	1					36
9	1					37
25	1					38
25	1					39
336	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
336	1					1
47	1					2
112	1					3
448	1					4
448	1					5
25	1					6
25	1					7
3	3					8
6	1					9
1	1					10
6	1					11
120	1					12
120	1					13
28	1					14
11	1					15
2	1					16
8	1					17
3	3					18
112	1					19
112	1					20
11	1					21
	3					22
14	1					23
14	1					24
70	1					25
70	1					26
50	2					27
47	1					28
47	1					29
1	1					30
47	1					31
50	1					32
20	1					33
23	1					34
7	1					35
120	1					36
120	1					37
120	1					38
50	1					39
50	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
37	1					1
70	1					2
47	1					3
448	1					4
448	1					5
1203	3					6
1203	3					7
7	1					8
14	1					9
2	1					10
7	1					11
11	1					12
11	1					13
112	1					14
187	1					15
28	1					16
47	1					17
672	1					18
672	1					19
47	1					20
47	1					21
14	1					22
14	1					23
47	1					24
47	1					25
28	1					26
10	3					27
28	1					28
25	1					29
22	1					30
14	1					31
14	1					32
7	1					33
6	1					34
63	1					35
63	1					36
63	1					37
28	1					38
28	1					39
	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
11	1					1
5	1					2
14	1					3
11	1					4
8	1					5
47	1					6
70	1					7
7	1					8
20	1					9
28	1					10
5	1					11
47	1					12
47	1					13
47	1					14
11	1					15
28	1					16
28	1					17
53	1					18
1	1					19
47	1					20
47	1					21
51	1					22
448	1					23
448	1					24
2	1					25
70	1					26
70	1					27
70	1					28
70	1					29
70	1					30
73	1					31
25	1					32
70	1					33
47	1					34
448	1					35
2	3					36
	3					37
19	1					38
11	1					39
14	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
63	1					1
63	1					2
22	1					3
14	1					4
14	1					5
11	1					6
120	1					7
120	1					8
47	1					9
11	1					10
28	1					11
84	1					12
84	1					13
84	1					14
84	1					15
70	1					16
3	1					17
168	1					18
70	1					19
7	1					20
70	1					21
70	1					22
2	1					23
4	1					24
28	1					25
28	1					26
5	1					27
3	1					28
112	1					29
28	1					30
70	1					31
47	1					32
70	1					33
28	1					34
28	1					35
14	1					36
5	1					37
28	1					38
28	1					39
47	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
47	1					2
47	1					3
47	1					4
47	1					5
70	1					6
25	1					7
47	1					8
2	1					9
11	1					10
3	1					11
70	1					12
70	1					13
28	1					14
28	1					15
2	3					16
2	1					17
336	1					18
3	1					19
3	1					20
70	1					21
47	1					22
25	1					23
28	1					24
1	3					25
14	1					26
70	1					27
70	1					28
47	1					29
47	1					30
47	1					31
47	1					32
6	1					33
6	1					34
63	1					35
63	1					36
672	1					37
1	1					38
14	1					39
11	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1					1
14	1					2
3	1					3
7	1					4
47	1					5
47	1					6
47	1					7
47	1					8
47	1					9
47	1					10
47	1					11
50	1					12
448	1					13
450	1					14
16	1					15
1	1					16
74	1					17
14	1					18
4	1					19
28	1					20
47	1					21
47	1					22
120	1					23
15	1					24
11	1					25
4	1					26
28	1					27
70	1					28
336	1					29
70	1					30
112	1					31
112	1					32
14	1					33
9	1					34
47	1					35
47	1					36
70	1					37
47	1					38
70	1					39
50	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
50	1					1
50	1					2
29	1					3
29	1					4
11	1					5
11	1					6
47	1					7
47	1					8
12	1					9
28	1					10
52	1					11
14	1					12
70	1					13
270	1					14
47	1					15
47	1					16
70	1					17
70	1					18
7	1					19
187	1					20
187	1					21
6	1					22
4	1					23
25	1					24
70	1					25
47	1					26
3	1					27
6	1					28
14	1					29
5	1					30
4	1					31
70	1					32
70	1					33
70	1					34
2	1					35
3	1					36
63	1					37
72	1					38
70	1					39
70	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
28	1					1
28	1					2
2	1					3
8	1					4
14	1					5
187	1					6
187	1					7
47	1					8
47	1					9
6	1					10
5	1					11
336	1					12
345	1					13
7	1					14
70	1					15
70	1					16
47	1					17
14	1					18
5	1					19
28	1					20
28	1					21
3	2					22
47	1					23
47	1					24
120	1					25
120	1					26
672	1					27
672	1					28
47	1					29
47	1					30
5	1					31
5	1					32
672	1					33
47	1					34
47	1					35
50	1					36
28	1					37
17	1					38
28	1					39
47	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
47	1					2
47	1					3
28	1					4
70	1					5
70	1					6
47	1					7
47	1					8
50	1					9
450	3					10
450	3					11
70	1					12
70	1					13
28	1					14
336	1					15
14	1					16
7	1					17
7	1					18
14	1					19
9	1					20
6	1					21
25	1					22
25	1					23
15	1					24
224	1					25
70	1					26
70	1					27
336	1					28
336	1					29
336	1					30
28	1					31
448	1					32
50	1					33
50	1					34
3	1					35
91	1					36
91	1					37
91	1					38
47	1					39
20	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
336	1					2
448	1					3
448	1					4
28	1					5
28	1					6
7	1					7
7	1					8
14	1					9
28	1					10
5	1					11
47	1					12
47	1					13
25	1					14
25	1					15
8	1					16
47	1					17
47	1					18
47	1					19
47	1					20
70	1					21
5	1					22
4	3					23
7	1					24
28	1					25
7	1					26
70	1					27
25	1					28
28	1					29
14	1					30
70	1					31
70	1					32
672	1					33
672	1					34
	1					35
112	1					36
336	1					37
28	1					38
28	1					39
448	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
187	1					1
187	1					2
28	1					3
28	1					4
28	1					5
28	1					6
14	1					7
47	1					8
47	1					9
53	1					10
47	1					11
187	1					12
1	1					13
74	1					14
5	1					15
28	1					16
28	1					17
70	1					18
70	1					19
63	1					20
1	3					21
187	1					22
336	1					23
448	1					24
448	1					25
5	1					26
5	1					27
42	1					28
42	1					29
14	1					30
4	1					31
7	1					32
70	1					33
70	1					34
70	1					35
70	1					36
6	1					37
47	1					38
47	1					39
47	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
47	1					1
11	1					2
70	1					3
70	1					4
10	3					5
10	3					6
10	3					7
10	3					8
10	3					9
10	3					10
47	1					11
47	1					12
47	1					13
672	1					14
672	1					15
4	1					16
5	1					17
5	1					18
70	1					19
70	1					20
70	1					21
70	1					22
70	1					23
70	1					24
28	1					25
8	1					26
73	1					27
3	1					28
11	1					29
20	1					30
22	1					31
10	1					32
2	3					33
70	1					34
14	1					35
28	1					36
28	1					37
7	1					38
11	1					39
14	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
2	1					1
4	1					2
4	1					3
4	1					4
5	1					5
11	1					6
11	1					7
70	1					8
70	1					9
28	1					10
112	1					11
112	1					12
22	1					13
7	1					14
28	1					15
112	1					16
112	1					17
70	1					18
73	1					19
70	1					20
70	1					21
70	1					22
70	1					23
70	1					24
70	1					25
70	1					26
70	1					27
70	1					28
112	1					29
70	1					30
70	1					31
70	1					32
70	1					33
	2					34
8	1					35
8	1					36
28	1					37
70	1					38
70	1					39
70	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
448	1					1
448	1					2
70	1					3
70	1					4
70	1					5
22	1					6
22	1					7
25	1					8
11	1					9
6	1					10
5	1					11
47	1					12
47	1					13
28	1					14
28	1					15
120	1					16
120	1					17
14	1					18
11	1					19
11	1					20
4	1					21
14	1					22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
5		1				34
5		1				35
120		1				36
2		1				37
28		1				38
28		1				39
14		1				40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
50		1				1
336		1				2
672		1				3
448		1				4
336		1				5
187		1				6
112		1				7
70		1				8
70		1				9
70		1				10
70		1				11
53		1				12
50		1				13
47		1				14
28		1				15
11		1				16
7		1				17
7		1				18
4		1				19
4		1				20
		1				21
11		1				22
5		1				23
112		1				24
50		1				25
50		1				26
5		1				27
5		1				28
47		1				29
47		1				30
5		1				31
5		1				32
866		1				33
47		1				34
50		1				35
14		1				36
						37
						38
						39
						40

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	Interchange agreement	NSP Wisconsin	557 and 566	177,233,726
3	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	-122,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	
5	Contribution of capital	Xcel Energy Inc.	207	-145,003,018
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	-838,000,000
7	Company labor, benefits, and related payments	NSP Wisconsin	see note	275,387
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Company labor, benefits, and related payments	NSP Wisconsin	see note	-7,053,218
22	Interchange agreement	NSP Wisconsin	456	-490,221,134
23	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	753,000,000
24	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	122,000,000
25	Dividends on common stock	Xcel Energy Inc.	215/216	407,906,850
26	Advances to Affiliates	United Power and Land Co.	123.1	
27	Vehicle and equipment use	NSP Wisconsin	see note	-1,771,876
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 4 Column: c

Service Function Group	FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	48,401
	108-Accum Dep	(202,819)
	186-Misc Deferred Debits	289
	408-409-Taxes	918,906
	417-421-Other Income	(1,209,197)
	426.1-426.5-Other Income Deductions	(40,867)
	430-431-Interest Charges	52,670
	500-514-Steam Power Generation	(43,729)
	517-532-Nuclear Power Generation	51,346
	535-545-Hydraulic Power Generation	133
	546-557-Other Power Generation	200,273
	560-573-Transmission Expenses	317,850
	580-598-Distribution Expenses	6,358
	710-759-Manufactured Gas Production	20,044
	807-813-Other Gas Supply Expenses	28,325
	850-870-Transmission Expenses	4,594
	871-893-Distribution Expenses	29,858
	901-905-Customer Accounts Expenses	23
	920-935-Administrative and General Expense	23,955,771
Accounting, Financial Reporting & Taxes Total		24,138,229
Aviation Services	408-409-Taxes	28,834
	417-421-Other Income	2
	426.1-426.5-Other Income Deductions	271
	500-514-Steam Power Generation	152
	517-532-Nuclear Power Generation	406
	535-545-Hydraulic Power Generation	1
	546-557-Other Power Generation	72
	560-573-Transmission Expenses	211
	580-598-Distribution Expenses	148
	710-759-Manufactured Gas Production	1
	807-813-Other Gas Supply Expenses	2
	814-826-Underground Storage Expenses	6
	850-870-Transmission Expenses	8
	871-893-Distribution Expenses	50
	920-935-Administrative and General Expense	2,506,538
Aviation Services Total		2,536,702
Business Systems	107-CWIP	88,620,403
	108-Accum Dep	5,263
	408-409-Taxes	1,325,193
	417-421-Other Income	38,840
	426.1-426.5-Other Income Deductions	624,736
	500-514-Steam Power Generation	1,698,062
	517-532-Nuclear Power Generation	5,985,791
	535-545-Hydraulic Power Generation	5,726
	546-557-Other Power Generation	407,373
	560-573-Transmission Expenses	5,473,490

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	580-598-Distribution Expenses	3,016,814
	710-759-Manufactured Gas Production	4
	807-813-Other Gas Supply Expenses	3,230
	814-826-Underground Storage Expenses	1,711
	840-843.9-Other Storage Expenses	7,830
	850-870-Transmission Expenses	135,735
	871-893-Distribution Expenses	1,350,155
	901-905-Customer Accounts Expenses	5,601,651
	908-910-Customer Service and Informational Expenses	39,733
	920-935-Administrative and General Expense	111,449,774
Business Systems Total		225,791,514
Claims Services	408-409-Taxes	39,438
	920-935-Administrative and General Expense	739,180
Claims Services Total		778,618
Corporate Communications	107-CWIP	1,850
	182.3-Reg Assets	436,340
	254-Reg Liab	597
	408-409-Taxes	203,052
	417-421-Other Income	11,740
	426.1-426.5-Other Income Deductions	810,137
	546-557-Other Power Generation	696,753
	580-598-Distribution Expenses	307,159
	710-759-Manufactured Gas Production	6,801
	850-870-Transmission Expenses	15,870
	871-893-Distribution Expenses	5,409
	901-905-Customer Accounts Expenses	184
	908-910-Customer Service and Informational Expenses	948,992
	920-935-Administrative and General Expense	3,530,284
Corporate Communications Total		6,975,168
Corporate Strategy & Business Development	108-Accum Dep	6,398
	408-409-Taxes	77,062
	426.1-426.5-Other Income Deductions	15,607
	920-935-Administrative and General Expense	1,510,380
Corporate Strategy & Business Development Total		1,609,447
Customer Service	107-CWIP	13,882
	182.3-Reg Assets	1,259,414
	254-Reg Liab	508,238
	408-409-Taxes	961,290
	417-421-Other Income	16,177
	426.1-426.5-Other Income Deductions	13,563
	560-573-Transmission Expenses	1
	901-905-Customer Accounts Expenses	19,504,153
	908-910-Customer Service and Informational Expenses	346,510
	920-935-Administrative and General Expense	4,176,675
Customer Service Total		26,799,903
Employee Communications	107-CWIP	3,017
	408-409-Taxes	33,567
	426.1-426.5-Other Income Deductions	67
	517-532-Nuclear Power Generation	1,566

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	546-557-Other Power Generation	144,309
	920-935-Administrative and General Expense	664,762
Employee Communications Total		847,288
Energy Delivery - Engineering/Design	107-CWIP	28,400,434
	108-Accum Dep	176,811
	183-Preliminary Survey and Investigation Charges	96,128
	408-409-Taxes	797,959
	426.1-426.5-Other Income Deductions	29,334
	500-514-Steam Power Generation	13,656
	517-532-Nuclear Power Generation	8,697
	546-557-Other Power Generation	510
	560-573-Transmission Expenses	7,626,783
	580-598-Distribution Expenses	843,589
	710-759-Manufactured Gas Production	20,650
	850-870-Transmission Expenses	1,610,970
	871-893-Distribution Expenses	81,478
	901-905-Customer Accounts Expenses	(4)
	908-910-Customer Service and Informational Expenses	359
	920-935-Administrative and General Expense	3,591,215
Energy Delivery - Engineering/Design Total		43,298,569
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	912,638
	108-Accum Dep	21,625
	408-409-Taxes	430,054
	426.1-426.5-Other Income Deductions	11,068
	560-573-Transmission Expenses	4,250,951
	580-598-Distribution Expenses	3,504,054
	710-759-Manufactured Gas Production	7,934
	830-837-Natural Gas Storage Maintenance	6,123
	840-843.9-Other Storage Expenses	195,441
	844.1-847.8-Liquefied Natural Gas Terminaling Expenses	3,661
	850-870-Transmission Expenses	1,237,444
	871-893-Distribution Expenses	533,827
	908-910-Customer Service and Informational Expenses	7,928
	920-935-Administrative and General Expense	3,219,278
Energy Delivery Construction, Operations & Maintenance (COM) Total		14,342,026
Energy Markets - Fuel Procurement	107-CWIP	807
	408-409-Taxes	71,660
	500-514-Steam Power Generation	750,271
	546-557-Other Power Generation	150,775
	807-813-Other Gas Supply Expenses	344,237
	920-935-Administrative and General Expense	477,692
Energy Markets - Fuel Procurement Total		1,795,442
Energy Markets Regulated Trading & Marketing	107-CWIP	180
	408-409-Taxes	349,101
	426.1-426.5-Other Income Deductions	17,138
	500-514-Steam Power Generation	972
	535-545-Hydraulic Power Generation	1,964

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	546-557-Other Power Generation	4,317,591
	560-573-Transmission Expenses	426,743
	575.1-575.8-Regional Market Expenses	381,911
	807-813-Other Gas Supply Expenses	6,082
	908-910-Customer Service and Informational Expenses	8,916
	920-935-Administrative and General Expense	1,978,075
Energy Markets Regulated Trading & Marketing Total		7,488,673
Energy Supply Business Resources	107-CWIP	1,734,667
	108-Accum Dep	16,514
	253-Other Deferred Credits	204,188
	408-409-Taxes	512,244
	426.1-426.5-Other Income Deductions	2,214
	500-514-Steam Power Generation	8,932,585
	517-532-Nuclear Power Generation	548,367
	535-545-Hydraulic Power Generation	28,871
	546-557-Other Power Generation	1,646,352
	560-573-Transmission Expenses	456
	580-598-Distribution Expenses	6,202
	840-843.9-Other Storage Expenses	(281)
	850-870-Transmission Expenses	1,217
	871-893-Distribution Expenses	1,906
	908-910-Customer Service and Informational Expenses	6,218
	920-935-Administrative and General Expense	4,800,219
Energy Supply Business Resources Total		18,441,939
Energy Supply Engineering & Environmental	107-CWIP	4,320,695
	108-Accum Dep	414,664
	183-Preliminary Survey and Investigation Charges	647,181
	408-409-Taxes	255,443
	426.1-426.5-Other Income Deductions	13,893
	500-514-Steam Power Generation	977,466
	517-532-Nuclear Power Generation	11,191
	535-545-Hydraulic Power Generation	93,260
	546-557-Other Power Generation	358,571
	560-573-Transmission Expenses	74,846
	580-598-Distribution Expenses	52,607
	710-759-Manufactured Gas Production	19,117
	840-843.9-Other Storage Expenses	1,467
	850-870-Transmission Expenses	767
	871-893-Distribution Expenses	26,238
	920-935-Administrative and General Expense	3,776,314
Energy Supply Engineering & Environmental Total		11,043,720
Executive Management Services	107-CWIP	554,043
	182.3-Reg Assets	1,019
	186-Misc Deferred Debits	(33,096)
	408-409-Taxes	128,895
	426.1-426.5-Other Income Deductions	391,447
	500-514-Steam Power Generation	(11,401)
	535-545-Hydraulic Power Generation	(68)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

	546-557-Other Power Generation	(17,182)
	560-573-Transmission Expenses	(62,623)
	580-598-Distribution Expenses	(9,407)
	850-870-Transmission Expenses	182,229
	871-893-Distribution Expenses	(6,487)
	908-910-Customer Service and Informational Expenses	1,554
	920-935-Administrative and General Expense	4,316,121
Executive Management Services Total		5,435,044
Facilities & Real Estate	107-CWIP	2,322,289
	108-Accum Dep	2,153
	408-409-Taxes	134,894
	417-421-Other Income	44,697
	426.1-426.5-Other Income Deductions	99,123
	500-514-Steam Power Generation	2,297,952
	517-532-Nuclear Power Generation	7,980,542
	535-545-Hydraulic Power Generation	21,410
	546-557-Other Power Generation	1,102,339
	560-573-Transmission Expenses	2,306,336
	580-598-Distribution Expenses	2,671,218
	710-759-Manufactured Gas Production	13,948
	807-813-Other Gas Supply Expenses	11,052
	814-826-Underground Storage Expenses	96,648
	840-843.9-Other Storage Expenses	391
	850-870-Transmission Expenses	129,118
	871-893-Distribution Expenses	702,256
	901-905-Customer Accounts Expenses	4
	920-935-Administrative and General Expense	14,720,787
Facilities & Real Estate Total		34,657,157
Finance & Treasury	107-CWIP	71
	182.3-Reg Assets	11,409
	408-409-Taxes	243,668
	417-421-Other Income	(7,328)
	426.1-426.5-Other Income Deductions	5,474
	430-431-Interest Charges	1,108,360
	546-557-Other Power Generation	325,341
	850-870-Transmission Expenses	1,413
	920-935-Administrative and General Expense	11,719,084
Finance & Treasury Total		13,407,492
Fleet	107-CWIP	1,376,299
	580-598-Distribution Expenses	430
	901-905-Customer Accounts Expenses	35,515
	920-935-Administrative and General Expense	108,236
Fleet Total		1,520,480
Government Affairs	408-409-Taxes	32,426
	426.1-426.5-Other Income Deductions	706,114
	920-935-Administrative and General Expense	778,443
Government Affairs Total		1,516,983
Human Resources	107-CWIP	(197,417)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	108-Accum Dep	80
	183-Preliminary Survey and Investigation Charges	2,588
	408-409-Taxes	672,551
	426.1-426.5-Other Income Deductions	49,926
	500-514-Steam Power Generation	(18,239)
	517-532-Nuclear Power Generation	1,028,245
	546-557-Other Power Generation	5,384
	560-573-Transmission Expenses	223,272
	580-598-Distribution Expenses	771,852
	850-870-Transmission Expenses	544,628
	871-893-Distribution Expenses	335
	908-910-Customer Service and Informational Expenses	177,044
	920-935-Administrative and General Expense	31,370,323
Human Resources Total		34,630,572
Internal Audit	408-409-Taxes	53,737
	426.1-426.5-Other Income Deductions	236
	920-935-Administrative and General Expense	1,471,435
Internal Audit Total		1,525,408
Investor Relations	408-409-Taxes	19,352
	426.1-426.5-Other Income Deductions	1,131
	920-935-Administrative and General Expense	1,196,948
Investor Relations Total		1,217,431
Legal	107-CWIP	53,997
	108-Accum Dep	2,001
	183-Preliminary Survey and Investigation Charges	2,336
	408-409-Taxes	339,347
	426.1-426.5-Other Income Deductions	21,607
	517-532-Nuclear Power Generation	342,725
	560-573-Transmission Expenses	5,343
	580-598-Distribution Expenses	8
	710-759-Manufactured Gas Production	163,341
	901-905-Customer Accounts Expenses	3
	920-935-Administrative and General Expense	7,279,302
Legal Total		8,210,010
Marketing & Sales	182.3-Reg Assets	27,726,957
	408-409-Taxes	136,337
	417-421-Other Income	21,638
	426.1-426.5-Other Income Deductions	17,428
	500-514-Steam Power Generation	177
	901-905-Customer Accounts Expenses	3,331
	908-910-Customer Service and Informational Expenses	2,058,780
	920-935-Administrative and General Expense	5,881,182
Marketing & Sales Total		35,845,830
Payment & Reporting	107-CWIP	14,803
	408-409-Taxes	4,970
	920-935-Administrative and General Expense	328,042
Payment & Reporting Total		347,815
Payroll	107-CWIP	2,594

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			

FOOTNOTE DATA

	408-409-Taxes	57,044
	426.1-426.5-Other Income Deductions	108
	920-935-Administrative and General Expense	1,149,504
Payroll Total		1,209,250
Rates & Regulation	182.3-Reg Assets	3,692
	186-Misc Deferred Debits	3,826
	408-409-Taxes	177,226
	426.1-426.5-Other Income Deductions	45,270
	517-532-Nuclear Power Generation	50,000
	560-573-Transmission Expenses	(566,242)
	580-598-Distribution Expenses	(1,656,095)
	850-870-Transmission Expenses	(3,953)
	871-893-Distribution Expenses	(246,884)
	920-935-Administrative and General Expense	3,373,033
Rates & Regulation Total		1,179,873
Receipts Processing	408-409-Taxes	44,200
	426.1-426.5-Other Income Deductions	10,421
	901-905-Customer Accounts Expenses	391,206
	920-935-Administrative and General Expense	432,224
Receipts Processing Total		878,051
Supply Chain	107-CWIP	10,398,878
	108-Accum Dep	55,669
	183-Preliminary Survey and Investigation Charges	9,742
	186-Misc Deferred Debits	110,028
	254-Reg Liab	640
	408-409-Taxes	22,256
	426.1-426.5-Other Income Deductions	19,875
	560-573-Transmission Expenses	118,794
	575.1-575.8-Regional Market Expenses	16
	580-598-Distribution Expenses	9,111
	850-870-Transmission Expenses	9,834
	871-893-Distribution Expenses	2,051
	920-935-Administrative and General Expense	1,194,856
Supply Chain Total		11,951,750
Grand Total		539,420,384

Schedule Page: 429 Line No.: 7 Column: c

107	\$	85,489
108		8,404
184		110,970
502		2,973
511		248
513		326
538		1,603
542		40,458
543		2,812
544		10,246
553		161
560		3,820
562		97

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/06/2018	Year/Period of Report 2017/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

563	444
566	383
571	488
584	275
586	339
587	311
588	2,082
592	494
593	2,010
594	5
874	468
875	193
878	100
902	96
920	92
	\$ 275,387

Schedule Page: 429 Line No.: 21 Column: c

107	\$ (5,906,223)
108	(420,262)
184	(56,774)
408.1	61
500	(865)
501	(3,122)
506	(3,000)
511	(41,495)
512	(168,854)
513	(5,054)
538	(440)
539	(4,597)
541	(2,192)
542	(6)
543	(893)
544	(454)
548	(397)
552	(20,133)
553	(10,179)
563	(1,758)
564	(357)
570	(22,327)
571	(18,128)
572	(295)
582	(231)
583	65
584	(3)
585	(1,336)
586	(48,234)
587	(1,002)
588	(36,490)
592	(1,124)
593	(45,791)
594	(774)
596	(5)
597	(5,173)
841	(2,078)
843	(900)
843.3	(7,803)
843.6	(190)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/06/2018	2017/Q4
FOOTNOTE DATA			

874	(15,343)
875	(193)
878	(451)
879	(16)
880	(4,700)
887	(164,859)
889	(7,745)
892	(236)
893	(10,928)
902	(62)
903	(8,941)
910	(1,070)
925	2
926	137
	\$ (7,053,218)

Schedule Page: 429 Line No.: 27 Column: c

107	\$ (1,624,582)
108	(79,182)
184	(198)
511	(410)
512	(2,768)
552	(1,199)
553	(511)
563	(17)
570	(6,928)
571	(27,176)
586	(6,215)
587	(230)
588	(6,184)
592	(621)
593	(7,852)
594	(94)
597	(338)
843.3	(663)
874	(30)
875	(22)
887	(6,622)
893	(34)
	\$ (1,771,876)

INDEX

<u>Schedule</u>	<u>Page No.</u>
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
	272-277
Accumulated provisions for depreciation of	
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	i
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
expense	254
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

<u>Schedule</u>	<u>Page No.</u>
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219
	336-337
Directors	105
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	101
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101

<u>Schedule</u>	<u>Page No.</u>
Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337
	401-429

<u>Schedule</u>	<u>Page No.</u>
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation	
amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred	
income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income	
from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Substations	426
Supplies - materials and	227

<u>Schedule</u>	<u>Page No.</u>
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230