MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___

Direct Testimony
of
Nicole A. Kivisto

Q. Please state your name and business address.

A. My name is Nicole A. Kivisto and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer (CEO) of Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. I am also the President and CEO of Cascade Natural Gas Corporation and Intermountain Gas Company; subsidiaries of MDU Resources Group, Inc.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of North Dakota and Wyoming, the Public Utilities Commissions of Idaho, Minnesota, Oregon and South Dakota, and the Washington Utilities and Transportation Commission.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above mentioned companies that, in combination, serve over one million customers in eight states.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Accounting from Minnesota State University Moorhead. I have worked for MDU Resources/Montana-Dakota since 1995 and have been in my current capacity since January 2015. I was the Vice President-Operations of Montana-Dakota and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. from January of 2014 until assuming my present position.

Prior to that, I was the Vice President, Controller and Chief Accounting Officer for MDU Resources for nearly four years, and held other finance related positions prior to that.

Q. What is the purpose of your testimony?

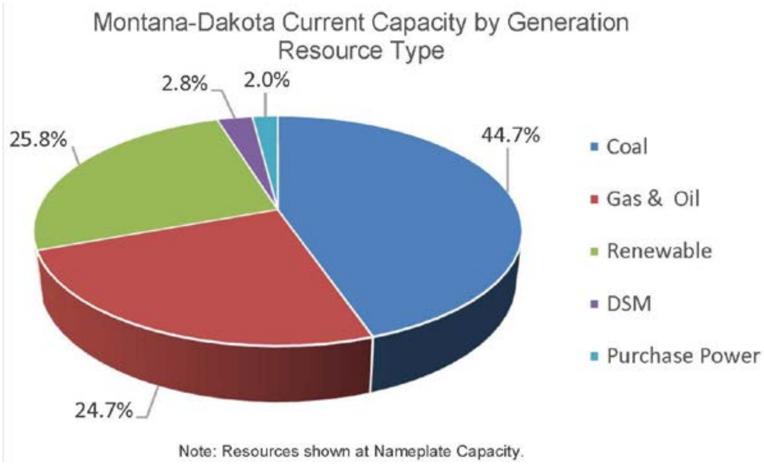
A. The purpose of my testimony is to provide an overview of the Company's Montana electric operations, explain the Company's request for an electric rate increase and the reasons underlying the major aspects of the request. I will also address the request for an interim increase and introduce the other Company witnesses that will present testimony and exhibits in further support of the Company's request.

Q. Would you provide a summary of Montana-Dakota's electric operations in Montana?

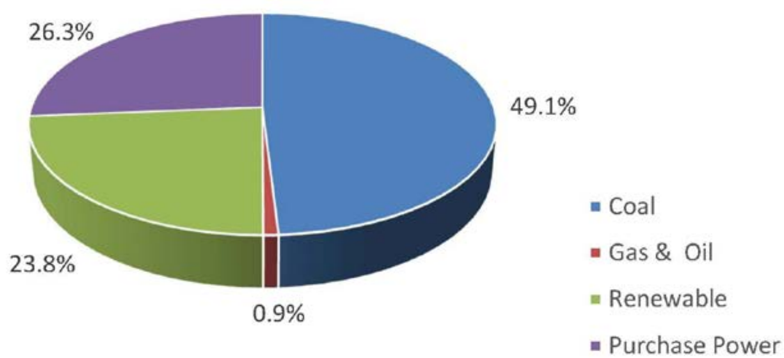
A. Montana is a part of Montana-Dakota’s interconnected electric system, which consists of generation, transmission, distribution, and general plant facilities serving approximately 25,770 customers in 30 communities in Montana. The Company’s Montana electric service area is served under one operating region with the regional office located in Dickinson, North Dakota and a number of district offices located in communities throughout Montana. As of December 31, 2017, the Company had 145 full and part time employees who live and work throughout our Montana electric and gas service area.

Q. **Describe Montana-Dakota’s interconnected electric system.**

A. Through its interconnected electric system, Montana-Dakota serves approximately 127,000 retail customers in portions of Montana, North Dakota, and South Dakota. The Company’s capacity mix is as shown below including the addition of the 48 MW of wind resources at the Thunder Spirit site that is currently in the commissioning phase as more fully explained by Mr. Neigum. In addition to the expansion of the Thunder Spirit facility, approximately 15 MW of additional demand side management (DSM) resources have been provided by customers bringing the DSM available to approximately 50 MW.



Customers' energy requirements are provided by the following resources including the Thunder Spirit Wind expansion.



Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for an electric rate increase?

A. Montana-Dakota is requesting an increase in its general electric rates at this time because our current rates do not reflect the cost of providing electric service to our Montana customers.

Q. What is the amount of the increase requested?

A. As will be fully explained by other Company witnesses, the Company is requesting an electric rate increase of $11,882,128 (an 18.9 percent increase over current rates) based on a 2017 test year adjusted for known and measurable changes.

Q. How will the requested increase affect the various classes of customers?

A. The proposed percentage change in rates by customer class is as follows:

Class	Percent
Residential	22.0%
Small General	18.8%
Large General	17.1%
Municipal Pumping	22.8%
Lighting	21.5%

This proposed increase reflects an increase of $16.23 per month or approximately $194.79 on an annual basis for a typical residential customer.

Q. Is Montana-Dakota continuing to follow the plan outlined in the most recently filed Integrated Resource Plan in Montana?

A. Yes. As explained in Mr. Neigum's testimony, the build out of the Thunder Spirit wind site resulting in the addition of sixteen 3 MW turbines or 48 MW of wind energy was identified in the 2017 IRP as a least cost resource for meeting customers' energy requirements. The Company is also continuing with its working assumption as outlined in the IRP, to retire the Lewis & Clark 1, Heskett 1 and Heskett 2 stations by 2025. This assumption is predicated on the cost of future environmental regulations, current coal contracts, the age of the facilities, and the economics of running the plants. The 2019 IRP is currently underway, including a Request for Proposal for capacity and energy resources beyond 2025, and will provide the additional analysis necessary to identify what type of resource is the best fit for meeting the needs of its customers beyond the plant retirements currently planned for 2025. The Company will be providing additional details as this proceeds.

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The primary reasons for the need for an increase in electric rates is the investment of approximately $68 million in facilities providing service to Montana electric customers since the last rate case; increased depreciation rates under a new depreciation study based on investments made since the last depreciation study in 2015; and increases in operation and maintenance expenses.

Q. Have the benefits of the Tax Cuts and Jobs Act of 2017 (TCJA) been reflected in this request for increased revenues?

A. Yes. As explained in further detail by Mr. Jacobson, the TCJA provided a substantial reduction in income taxes that offset the increase required in this rate case.

Q. Ms. Kivisto would you please elaborate on the reasons driving the need for a rate case at this time?

A. Yes. While Montana-Dakota strives to provide customers with safe and reliable service at economical rates, the investments necessary to meet customers' demand along with investments necessary to meet environmental regulations and to provide safe and reliable service continue to increase at a faster pace than customer growth and efficiencies that would offset the increased costs. Again, the major reason for this request is driven by the investments that have been made since the last rate case. Following is a summary of the $68 million invested by type of investment:

	Million
Generation - Environmental Related	$6
Generation - Operational Enhancements	10
Thunder Spirit Expansion	23
Transmission	13
Distribution	10
Vehicles, Facilities, Software, Cyber Security	6
Total Investment Since Last Rate Case	$68

1. The environmental investments required at the Lewis & Clark Station 1 and the Heskett Stations since the last rate case have contributed to the need for rate relief. These investments, determined to be economic, were required to keep the plants in operation at least until 2025. The investment at these stations along

with updated decommissioning studies for the wind facilities have also caused a significant increase in depreciation and decommissioning costs as further discussed by other Company witnesses.

2. Investments in the Company's fleet of generators have been made to enhance operational efficiencies and to maintain the units as necessary.

3. The increase in the revenue requirement caused by the addition of the 48 MW Thunder Spirit Expansion project, expected to be placed in service in October of this year is approximately $1.5 million. However, the Thunder Spirit expansion will offset market purchases and higher priced generation with those savings flowing back to customers through the Fuel and Purchase Power Adjustment. As a result of the savings, the net impact to customers is expected to be just under $335,000.

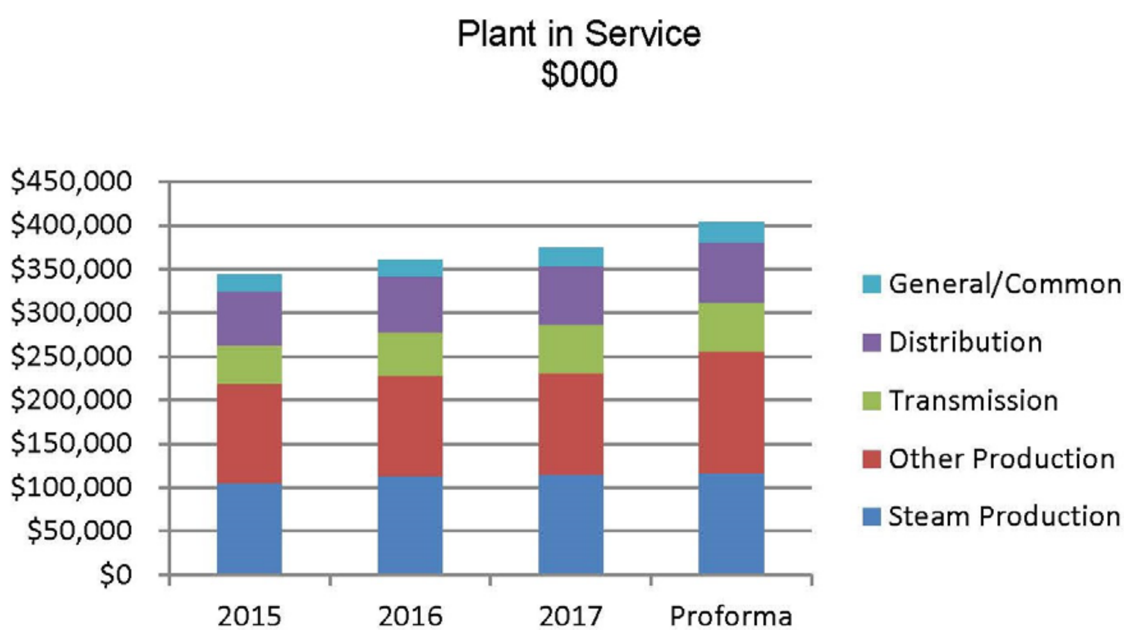
4. Investments in transmission and distribution facilities necessary to maintain and enhance the reliability of the system have been made and additional investment is underway today. The Company also recently replaced the lighting systems in 29 communities, where the Company owned the lighting systems, with LED fixtures. While the increase in investment will be borne by those cities through facility charges, the lighting change out provided a net benefit to the

communities through reduced electricity usage in addition to providing better lighting.

5. Investments in work equipment, facilities and software including cyber security requirements are necessary on an ongoing basis.

With each of these investments, there is additional depreciation, operation and maintenance expenses and taxes associated with the increases in investment.

The table below shows the investment in electric plant assigned and allocated to Montana electric operations from 2015 to pro forma 2018.



Q. When was the last general electric rate increase for Montana-Dakota in Montana?

A Montana-Dakota's last general electric rate case was Docket No. D2015.6.51 which resulted in a two-phase increase totaling $7.7 million or 14 percent that became effective on April 1, 2016 and April 1, 2017.

Q. What return is Montana-Dakota requesting in this case?

Montana-Dakota is requesting an overall return of 7.542 percent, inclusive of a return on equity (ROE) of 10.3 percent. Ms. Bulkley's analysis indicates that a 10.3 percent ROE is fully justified and supported based on the results of her studies.

Q. Is Montana-Dakota seeking interim rate relief in this proceeding?

A. Yes. Interim rate relief is being sought in this case consistent with the Administrative Rules of Montana (ARM) § 38.5.5 Interim Utility Rate Increases. The amount of interim relief sought is $4,596,161 and reflects the Company's additional generation facilities and other adjustments included in the pro forma 2017 revenue requirement based on Commission guidelines as described by Mr. Jacobson. The Company's reported returns the last two years of 4.21 percent and 5.54 percent for its Montana electric operations support the need for interim rate relief while this rate case is being processed.

Q. Is the Company seeking a change in any of the cost recovery mechanisms in this case?

A. Yes. The Fuel and Purchased Power Cost Adjustment currently includes charges through energy markets in the Regional Transmission Organizations (RTO's). The Company is proposing to expand the Fuel and Purchased Power Cost Tracking Adjustment Rate 58 to include the net transmission service costs providing access to RTO market energy as more fully explained by Mr. Neigum and Mr. Jacobson.

Q. Will you please identify the witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes. Following is a list of witnesses that will provide testimony and/or exhibits in support of the Company's application:

- Mr. Jay Skabo, Vice President of Electric Supply for Montana-Dakota, will provide an overview of the Company's generation resources and required environmental additions and support for the increase in depreciation.
- Mr. Darcy J. Neigum, Director of System Operations and Planning for Montana-Dakota, will testify regarding the need and justification for the Thunder Spirit addition. Mr. Neigum will also discuss the nexus between transmission service and other RTO costs currently recovered through the Fuel and Purchased Power Adjustment.
- Ms. Tammy J. Nygard, Controller for Montana-Dakota, will testify regarding the overall cost of capital, capital structure and overall debt costs, including the preferred stock redemption.
- Ms. Ann Bulkley, Senior Vice President of Concentric Energy Advisors, Inc. will testify regarding the appropriate cost of common equity for Montana-Dakota's Montana electric operations.
- Mr. Larry Kennedy, Senior Vice President of Concentric Energy Advisors, Inc. will testify regarding the depreciation study for Montana-Dakota's electric operations.

- Mr. Travis R. Jacobson, Regulatory Analysis Manager for Montana-Dakota, will testify regarding the total revenue requirement and the interim revenue requirement necessary for Montana electric operations.
- Mr. Jordan R. Hatzenbuhler, Senior Regulatory Analyst for Montana-Dakota will testify regarding the Company's embedded class cost of service study and proposed rate design.
- Mr. Ralph Zarumba, Vice President with Concentric Energy Advisors, Inc. will testify regarding the marginal cost of service study for Montana-Dakota's Montana electric operations.
- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota will testify regarding proposed tariff changes.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by Montana-Dakota in providing safe and reliable electric service to its customers. The proposed rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its Montana electric operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___

Direct Testimony
of
Jay Skabo

Q. Please state your name and business address.

A. My name is Jay Skabo and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Vice President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. My responsibilities include oversight of the departments that manage power production and transmission, environmental, system operations and planning, and electric dispatch.

Q. Please outline your educational and professional background.

A. I hold Bachelor's Degrees in Chemistry from Dickinson State University and Chemical Engineering from the University of North Dakota. My work experience includes three and a half years as the Environmental Manager at Montana-Dakota; one and a half years as a Region Manager overseeing gas and electric crews, service technicians, and office personnel in constructing and maintaining our gas and electric systems. In 2008, I became Vice President of Operations. In January 2014, I assumed my current position. Prior to joining Montana-Dakota, I was the general manager of an industrial waste processing and disposal facility.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes, I have testified before the North Dakota and Montana Public Service Commissions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information regarding Montana-Dakota's future view of its generation portfolio, provide support for the increase in depreciation expense related to generation assets and the modifications at the Lewis & Clark Station needed for compliance with the U.S. Environmental Protection Agency's (EPA) Coal Combustion Residuals (CCR) Rule.

Q. Please describe Montana-Dakota's current portfolio of generation assets used to serve customers and changes transpiring in 2018.

A. Montana-Dakota's existing generation serving its interconnected electric system is comprised of baseload coal-fired generation at the Heskett Station (Units 1 and 2), the Lewis & Clark Station, Montana-Dakota's share of the Coyote and Big Stone Stations, and natural gas-fired peaking generation at Glendive (Units 1 and 2), Miles City, Heskett Unit 3, and Lewis & Clark Station 2 (also known as the "RICE units").

Montana-Dakota also owns the Diamond Willow, Cedar Hills and Thunder Spirit wind farms, two (2) MW portable diesel units, and the Glen Ullin Station 6 waste heat generating unit. The remainder of customer requirements has been provided by energy purchases from the MISO energy market. To meet growing needs and increase reliability, and to reduce reliance on the MISO energy market, construction of a 48 MW expansion of the Thunder Spirit wind facility is nearing completion.

Mr. Darcy Neigum will provide additional details regarding the selection of the new generating unit as a least cost resource as part of the 2017 Integrated Resource Plan (IRP) including the justification of need.

Q. Retirements were identified in the 2015 and 2017 IRPs for the Heskett and Lewis & Clark coal fired units. Is this assumption still valid today?

A. Yes. In the 2017 IRP, the Heskett 1, Heskett 2 and Lewis & Clark 1 units were considered in the modeling to be retired by the end of 2024. The assumptions underlying this consideration were that additional environmental requirements and operation and maintenance costs associated with the age of the units would result in a future retirement. Additional factors playing into this assumption now include the future of economic coal deliveries and the economic competitiveness of the plants in the MISO energy market. These factors require the Company to continue to study, evaluate and pursue the retirement of the plants in the near term. The depreciation end of life continues to be set at 2025 for Lewis & Clark 1 as it was in the last depreciation study submitted in Docket No. D2015.6.51. In the Depreciation Study presented in this case, the Heskett Units have also been set to retire in 2025.

Q. Does the resource expansion model (EGEAS) used in the IRP pick an optimal unit retirement date?

A. No, the Electric Generation Expansion Analysis System (EGEAS) will not specifically choose when to retire a unit but it can be a tool to help make a better business decision. Montana-Dakota's 2019 IRP will include specific analyses to determine whether the 2025 time-frame continues to be an advantageous time to retire the units in order to economically and reliably serve customers.

Q. What are the commercial operation dates and ages of the coal-fired units at the Heskett and Lewis & Clark Stations?

A. Heskett Unit 1 began commercial operation in 1954 and has been in service for 64 years. Lewis & Clark Unit 1 began commercial operation in 1958 and has been in service for 60 years. Heskett Unit 2 began commercial operation in 1963 and has been in service for 55 years. In 2025, these units will have been in service for 71, 67, and 62 years, respectively.

Q. Please describe the current condition of these units.

A. Considering their age, the Heskett and Lewis & Clark coal-fired units are in good condition and have no major components in poor condition or identified as facing risk of near term failure.

Q. Please describe Montana-Dakota's philosophy for adjusting the operating life span of the aging Heskett and Lewis & Clark Station coal-fired units over time.

A. A series of interdependent investments including some retrofits and environmental-driven major modifications over time have resulted in continued operation and lengthening the relevant operating life span of these facilities. Ongoing maintenance including incremental replacement of some components, along with quality operating methods have resulted in the service lives exceeding the design lives of the major components and have made it economically feasible and efficient to continue operating these units.

Q. What are the factors causing Montana-Dakota to consider firming up the end of life dates, adjusting the depreciation rates, and to begin to develop plans to retire and decommission the Heskett and Lewis & Clark Station coal-fired units?

A. The factors include age and growing risk of component failures and obsolescence, increased net book value (primarily caused by large environmental projects which will allow the plants to continue to operate until at least 2025), potential for future environmental rules causing additional large investments, IRP analysis, increasing O&M costs, and loss of competitiveness in the market.

Q. Would you please generally describe the reasons for the increase in generation related depreciation expense since the 2015 Depreciation Study?

As detailed in the Depreciation Study supported by Mr. Larry Kennedy, the increase in the net book value of the Heskett and Lewis & Clark Stations along with the Thunder Spirit expansion and the Air Quality Control System investments in the Big Stone Plant have caused a significant increase in depreciation expense related to generation. These environmental upgrades were necessary to continue operating the plants for the benefit of customers. The end of service life for the Heskett Units was also changed from 2028 to 2025 contributing to the increase.

Q. What is the current book value of the Lewis & Clark 1 and Heskett Units?

A. The current Net Plant in Service for these units, including the Scrubber Pond Project at the Lewis & Clark Station is as follows:

- Lewis & Clark Unit 1 - $47.2 million
- Heskett Units 1 and 2 - $55.2 million

Q. What has caused the increase in book value over the year end 2014 values used in the 2015 Depreciation Study?

A. The table below provides a list of the environmental projects that have been installed at the Heskett and Lewis & Clark Stations since 2014.

In addition to the environmental projects at the Heskett and Lewis & Clark Stations, approximately $86 million was added to the Big Stone Station for the required Air Quality Control System.

Location	Project	In-Service	$MM
Lewis & Clark 1	Scrubber Equipment Modifications	2015	16.6
Lewis & Clark 1	Ash Settling Tank Addition	2015	5.3
Lewis & Clark 1	Fly Ash System Modifications for dry handling	2016	8.7
Heskett 2	Limestone Equipment for SO_2 Reduction	2016	9.2
Lewis & Clark 1	Scrubber Pond Modifications	2018	5.3

Q. Please describe the Coal Combustion Residuals Rule.

A. EPA proposed a rule in 2010 to provide requirements for the safe disposal of coal ash from coal-fired power plants. EPA published the final CCR Rule on April 17, 2015, establishing requirements for both existing and new CCR landfills and CCR surface impoundments. The rule requires CCR surface impoundments to meet specific criteria involving structural integrity, operating criteria, liner design, location restrictions, record keeping, notification and internet posting, and groundwater monitoring and corrective action.

Q. What has MDU done to address the requirements of the CCR Rule?

A. In 2015, the Lewis & Clark Station implemented an ash system project as a result of the CCR rule. The project consisted of three main parts: (1) retirement of the large ash pond; (2) construction of a new concrete bottom ash settling tank; and (3) modifications necessary to handle fly ash entirely as a dry material. The pond was dried out and retired in 2015, with final capping and shaping in 2018, and replaced with a new concrete bottom ash settling tank which was completed during the outage for the Mercury and Air Toxics Standard (MATS) project. Lewis & Clark converted to dry fly ash management to minimize the size and cost of the new concrete bottom ash settling tank. Converting to dry fly ash management involved adding equipment and making modifications to handle fly ash entirely as a dry material from the collection hopper through transportation in trucks to the ash disposal site. The Lewis & Clark Station installed this portion of the project in phases, with the dry fly ash management system operational on April 14, 2016.

To comply with certain CCR surface impoundment requirements, the Lewis & Clark Station is completing the Scrubber Pond Project in 2018.

Q. What are the Scrubber Pond Project modifications required by the CCR Rule?

A. The Scrubber Pond Project involves retrofitting the scrubber ponds, consisting of the following actions: removal of CCR materials, deconstruction of berms, re-establishment of base and berms, construction of a new composite liner system composed of geosynthetic clay liner and geomembrane, application of liner cover materials, modification of the existing pump house, and construction of a haul road and access ramps. In addition, a related temporary storage pad for dewatering flue gas desulfurization solids prior to transport and disposal needed to be closed and reconstructed due to the scrubber pond retrofit.

Q. When does the CCR rule require the Scrubber Pond Project to be complete?

A. Montana-Dakota is required to demonstrate by October 17, 2018, that the Scrubber Ponds meet all of the CCR Rule's location restrictions, including obtaining the necessary certifications from a qualified professional engineer concerning the impoundment's construction.

Q. Please describe the sequence of construction and schedule for the Scrubber Pond Project.

A. To allow Lewis & Clark Unit 1 to remain in operation during construction, the Scrubber Pond Project construction was to be completed in phases. The temporary storage pad was closed during the first phase of the project. During the scrubber pond retrofit activities, one of the two ponds will remain in operation while the other pond is taken out of service for retrofitting. The West Scrubber Pond was the first to undergo retrofit, followed by the East Scrubber Pond - which is to be completed in early October.

Q. Please describe the cost of the Lewis & Clark Station Scrubber Pond Project.

A. The total projected cost of the Scrubber Pond Project is estimated at $5,333,500 with $1,267,156 allocated to Montana.

Q. Is the Scrubber Pond Project expected to result in changes to the Lewis & Clark Unit 1 operation?

A. The Scrubber Pond Project will not significantly change the process or cost of operations. However, completing the project will allow the plant to continue operating beyond October 31, 2020. This closure date was recently extended through a CCR rule amendment published on July 30, 2018. The original date that a unit would have had to close would have been no later than April 17, 2019, without the Scrubber Pond Project.

Q. Has EPA made any changes to the CCR Rule that will impact the design or construction of the Scrubber Pond Project?

A. No. EPA requested comment on proposed amendments to the CCR Rule in early 2018 and finalized some of the proposed amendments in a rule published in the Federal Register on July 30, 2018. The recent amendments did not impact any of the Rule's provisions for CCR surface impoundments relevant to the Scrubber Pond Project. Separately, on December 16, 2016, Congress enacted the Water Infrastructure Improvements for the Nation (WIIN) Act providing the EPA and states the authority to administer and enforce CCR rule requirements through permitting programs. Administration of the CCR rule by the EPA and states may potentially result in availability of alternative compliance options. However, no states within Montana-Dakota service territory have yet adopted the authority to administer the CCR rule.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___

Direct Testimony
of
Darcy J. Neigum

Q. Please state your name and business address.

A. My name is Darcy J. Neigum and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Director of System Operations and Planning for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have managerial responsibility for overseeing the day-to-day operations of the Company's electric control center and system operations and planning department. The system operations and planning department is responsible for electric resource planning and expansion studies for the Company.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Electrical and Electronics Engineering from North Dakota State University as well as a Masters of Business Administration from the University of Mary. My work experience includes four years as a nuclear plant engineer; three years of experience as a coal-fired power plant engineer; eleven years of generation development and operational responsibilities for coal-fired, gas-fired, and renewable generation sources; and ten years of experience managing the system operations & planning department for Montana-Dakota.

Q. What is the purpose of your testimony in this proceeding?

A. I provide support for the Company's investment in the Thunder Spirit Wind Expansion Project (Thunder Spirit Expansion or Project) as a generation resource for the Company's integrated electric system. I will also support the inclusion of Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) transmission charges and associated credits into the fuel and purchase power tracker.

<u>Thunder Spirit Wind Project Expansion</u>

Q. Please describe the Thunder Spirit Expansion.

A. The Thunder Spirit Wind project is a fully permitted and sited 150 MW wind project located in Adams County, North Dakota northeast of the City of Hettinger. Montana-Dakota acquired the first 107.5 MW phase of Thunder Spirit Wind project from ACE Wind LLC and Thunder Spirit Wind, LLC including all development rights, permits, agreements, and leases associated with the 150 MW project on December 30, 2015.

The first phase of Thunder Spirit Wind consisted of 43 Nordex N100/2500 (2.5 MW) wind turbines erected on 80-meter towers with a total output of 107.5 megawatt (MW) and a forecasted net capacity factor of 45.2 percent. The first phase of Thunder Spirit Wind was placed into commercial operation on December 31, 2015. The first two years production for the first phase of Thunder Spirit Wind were 427,960 MWh and 428,528 MWh resulting in 45.3 percent and 45.5 percent capacity factors, respectively.

The Thunder Spirit Expansion consists of 16 Nordex N117/3000 (3.0 MW) wind turbines totaling 48 MW with a hub height of 91 meters and an estimated capacity factor of 44.5 percent. The Thunder Spirit Wind Project interconnects at the adjacent Hettinger 230 kilovolt (kV) Junction Substation owned by Montana-Dakota and utilized by both phases.

Q. Can you describe the selection process for the Thunder Spirit Expansion?

A. Montana-Dakota issued a Request for Proposals of Capacity and Energy Resources (2016 RFP) on August 1, 2016 as part of the development of its 2017 Integrated Resource Plan (2017 IRP) submitted to the Commission on September 15, 2017. A copy of the RFP and summary of analysis of bids received were included in the 2017 IRP report.

ACE Wind LLC provided a proposal to Montana-Dakota through the 2016 RFP whereby they would develop the Thunder Spirit Expansion Project and sell the output of the Project to Montana-Dakota under a 25-year power purchase agreement which included an option for the Company to purchase the Project at its commercial operation date.

The ownership of the Thunder Spirit Expansion Project was selected as a least cost resource for the Company as part of the 2017 IRP planning process to meet customers current and growing energy requirements.

Q. Can you describe the transaction with ACE Wind LLC regarding the Thunder Spirit Expansion Project?

A. On December 22, 2016, Montana-Dakota signed a development rights agreement and a power purchase agreement (PPA) with ACE Wind LLC and Thunder Spirit Wind, LLC for the design, engineering, and construction of the Thunder Spirit Expansion Project utilizing certain permits, leases and agreements held by Montana-Dakota.

As part of the PPA, Montana-Dakota would either purchase the assets for the Thunder Spirit Expansion Project at its commercial operation date under a negotiated asset purchase agreement; or transfer sufficient rights, leases, and agreements to ACE Wind LLC and Thunder Spirit Wind, LLC for their ownership of the Project and Montana-Dakota would purchase all the energy and attributes from the Project under the executed PPA. Montana-Dakota exercised its option to purchase the Thunder Spirit Expansion Project at its commercial operation date on February 28, 2018.

Q. Can you describe the analysis process that Montana-Dakota conducted with Thunder Spirit Expansion Project as part of the 2017 IRP?

A. Montana-Dakota included the Thunder Spirit Expansion PPA as a supply option in the 2017 IRP. Separate model runs were conducted as part of the 2016 RFP analysis which led to the inclusion of the Thunder Spirit Expansion Project in the 2017 IRP analysis.

The 2017 IRP analysis selected the Thunder Spirit Expansion Project as a least cost resource in the base case and all sensitivity model runs.

A separate sensitivity was conducted whereby the 2017 IRP model could choose between the ownership option of the Thunder Spirit Expansion Project as well as the PPA option. The ownership option utilized a revenue requirement model to develop an annual revenue requirement and $/MWh cost for the Thunder Spirit Expansion Project over its 25-year life. The ownership of Thunder Spirit Expansion Project was selected as a least cost option over the PPA with $4.77 million in net present value savings over the PPA. Because the Thunder Spirit Expansion PPA was a least cost resource in the Base Case and all modeled scenarios, and the ownership option was selected over the PPA option, the Thunder Spirit Expansion ownership option is the overall least cost option as compared to the PPA.

Q. What was the modeled annual ownership cost of the Thunder Spirit Expansion Project?

A. The annual modeled revenue requirement for the ownership of the Project is:

Year	Rate ($/MWh)
1	25.97
2	19.74
3	15.63
4	11.38
5	7.82
6	4.75
7	2.72
8	1.21
9	-0.32
10	-1.84
11	42.30
12	41.45
13	40.60
14	39.78
15	38.98
16	38.17
17	37.36
18	36.56
19	35.76
20	34.96
21	40.91
22	40.35
23	39.80
24	39.26
25	38.73

Q. What levelized ownership cost was used for the Thunder Spirit Expansion Project in the 2017 IRP process?

A. The 25-year levelized ownership cost of the Thunder Spirit Expansion Project as modeled was $22.40 per MWh.

Q. What assumption was made regarding the availability of Federal Production Tax Credits (PTCs) for wind in the analysis of the Thunder Spirit Wind Expansion Project?

A. The analysis assumed the full PTCs were available over the first ten (10) years of the project life at 2.3 cents per kWh and a Federal Corporate Income Tax rate of 35 percent. The value of the PTC has currently been adjusted to 2.4 cents per kWh

Q. What impact did the reduction of the Federal Corporate Income Tax Rate from 35 percent to 21 percent have on the economics of the Thunder Spirit Expansion Project?

A. The economics of the Thunder Spirit Expansion Project are dependent on the PTCs that the Project receives. These PTCs off-set revenues that would otherwise be recovered from customers. The PTC is an after-tax credit and revenues that the PTCs offset from customers are collected on a pre-tax basis. Therefore, the value of the tax credit must be grossed up for income taxes to offset pre-tax customer payments to the Company. The reduction of the Federal Corporate Income Tax Rate from 35 percent to 21 percent reduces the grossed up value of the PTCs ($24 per MWh post tax) from $36.92 per MWh to $30.38 per MWh pre-tax. The 21% Federal Corporate Income Tax rate increases the 25-year levelized cost of the Thunder Spirit Expansion Project from $22.40 per MWh to $25.63 per MWh.

Even with the reduced value of the PTCs, the Thunder Spirit Expansion Project is still a least cost alternative for the Company as compared to other supply options, including the PPA for the Project.

Q. How do these prices compare with historic energy price that Montana-Dakota has purchased from the MISO Energy Market?

A. The annual average Montana-Dakota purchase price of energy over the last 5 years from the MISO Energy Market has been $24.95 per MWh. As a result, the models used during the 2017 IRP planning process (which were prior to the reduction in the federal tax rate) projected a net present value savings to customers of $19.1 million over the 25-year life of the Project as compared to forecasted MISO Market energy prices used in the 2017 IRP Base Case Model and $5.9 million in net present value savings in the Low Market Price scenario. In addition to the projected energy savings, the Thunder Spirit Expansion Project is expected to provide 8 MWs in annual capacity credits for meeting customer peak demand requirements.

Q. What assumptions were made in the Thunder Spirit Expansion Project analysis for future carbon pricing?

A. The base case in the 2017 IRP assumed no future carbon pricing. A modeling sensitivity utilizing a $30 per ton carbon tax was run. This carbon sensitivity also selected the Thunder Spirit Expansion Project.

Q. Can you describe the purchase option for the Thunder Spirit Expansion Project?

A. Montana-Dakota intends to purchase the Thunder Spirit Expansion Project at its commercial operation date as it is a least cost option for its customers. The purchase option, as defined in the PPA and asset purchase agreement, includes a purchase price due at closing with adjustments for specific additions or reductions of scope to the Project requested by Montana-Dakota. The purchase price includes a 20-year long-term maintenance supply agreement with the turbine manufacturer.

Montana-Dakota also estimated $1 million in additional owner costs specific for Montana-Dakota associated with the construction and acquisition of the Project. Assuming a final project size of 48 MWs, the total cost of the Thunder Spirit Project used in the model was $85 million. The total project cost with AFUDC and overheads is expected to be $86.377 million.

Q. Can you describe the long-term maintenance supply agreement (LMSA) included in the purchase option for the Thunder Spirit Expansion Project?

A. The LMSA is a 20-year agreement with the turbine manufacturer which includes all maintenance and replacement parts at a fixed cost over the term of the agreement, excluding events of force majeure, along with an annual availability guarantee for the associated performance of the Project. The LMSA arrangement reduces the unknown cost of future maintenance including major maintenance costs and components. Montana-Dakota will still be responsible for additional maintenance costs associated with force majeure events.

Q. Are there any other benefits that the LMSA provides?

A. Yes, the turbine manufacturer also made available to Montana-Dakota a negotiated fixed price long-term maintenance supply agreement for the first phase of the Thunder Spirit Wind project which originally only had a two-year warranty and five-year maintenance supply agreement. The LMSA for the original project will reduce future maintenance cost uncertainty and provide savings to Montana-Dakota's customers.

Q. What are the annual savings of the ownership option of the Thunder Spirit Expansion Project over the PPA option?

A. Looking at the difference between the annual revenue requirements in the Thunder Spirit Ownership sensitivity versus the Base Case in the 2017 IRP analysis, the following annual cost differences are calculated between the two options:

Annual Cost ($Millions)

	Thunder Spirit Ownership	Base Case	Difference
2019	87.6	86.2	1.3
2020	95.0	94.8	0.2
2021	97.7	98.5	-0.8
2022	101.2	102.8	-1.6
2023	105.0	107.2	-2.2
2024	108.5	111.3	-2.8
2025	134.0	137.2	-3.2
2026	153.6	157.1	-3.5
2027	157.7	161.4	-3.7
2028	162.5	166.5	-4.0
2029	177.7	175.6	2.1
2030	186.7	184.8	1.9
2031	192.0	190.2	1.8
2032	197.6	196.0	1.6
2033	203.8	202.4	1.5
2034	210.6	209.2	1.4
2035	237.9	236.7	1.3
2036	245.3	244.2	1.1
		NPV @ 6.12% WACC	-7.26

Q. How will Montana-Dakota utilize Thunder Spirit Expansion to meet customer needs?

A. The Thunder Spirit Expansion will help keep energy prices to Montana-Dakota's customers as low as possible. Since the expiration of the 66 MW Antelope Valley Station Unit II PPA with Basin Electric in 2006, Montana-Dakota has been a net purchaser of energy from others to meet its customers' energy requirements. The Company's 2017 IRP assumed a five year customer energy requirement growth of 1.11%. The amount of energy that Montana-Dakota purchases from the MISO energy market has grown from 10 percent, or 308,000 MWhs, in 2007 to 24 percent, or 766,000 MWhs, in 2016 despite the addition of generation resources during that time period.

Ownership provides Montana-Dakota with control of the Project site and equipment along with the ability to capture additional value from the Project after the expiration of a PPA. All the wind energy purchased under the PPA is at a contract price and if the Project generates more energy than the P50 wind forecast (50/50 historic wind potential) the Company still pays the contract price for all the energy above the P50 output level. Under an ownership scenario the customers receive the benefits for this additional generation without an additional charge.

Thunder Spirit Expansion is a low-cost generation resource opportunity for Montana-Dakota that provides numerous benefits including price protection against future MISO energy prices, price protection against increases in future natural gas prices, greater fuel source diversity in the Company's generation mix, and the ability to capture significant value from Federal PTCs which are scheduled to phase out over time.

Q. How will Thunder Spirit Expansion qualify for the full Federal Production Tax Credit (PTC) for wind?

A. Wind projects which started construction before the end of 2016 are eligible to receive the full PTC value if they complete their construction within three years from the start of construction date. Projects which start construction in 2017 are eligible to receive 80 percent of the PTC value. Projects which start construction in 2018 are eligible to receive 60 percent of the PTC value. Projects which start construction in 2019 are eligible to receive 40 percent of the PTC value. Projects which start construction after 2019 are not eligible to receive PTCs.

For qualification of the Federal PTCs, the Thunder Spirit Expansion Project will be considered a new project with a separate start of construction date from the original project.

ACE Wind LLC and Montana-Dakota undertook efforts in the fall of 2016 to construct various Project roads sufficient to qualify as start of construction under current United States Internal Revenue Service (IRS) guidelines. ACE Wind LLC also purchased the Project turbine equipment at the end of 2016 which qualifies as Safe Harbor Equipment under IRS guidelines and which can also be used to show start of construction for the Project occurred in 2016. Therefore, the Expansion Project will qualify for 100 percent of the PTC value.

Q. What is the status of the Project?

A. ACE Wind LLC purchased the wind turbines for the Project from Nordex and contracted with Wanzek Construction to perform all the civil, mechanical, electrical, and commissioning work for the Project.

All the Project lease agreements are in place.

The existing Thunder Spirit Interconnection agreement with MISO is for a 150 MW project size and no network upgrades are required for the Thunder Spirit Expansion Project. The Project collector substation was engineered and built to support the 150 MW project size with minimal additions needed.

Q. What is the construction schedule for the Project?

A. Wanzek mobilized to the site on May 8, 2018. Turbine deliveries to the site were completed on July 31, 2018. All turbine foundation work was completed on August 7, 2018.

Turbine erection was completed in August 2018, with the exception of one turbine which has a damaged tower section that will be erected by the end of 2018. Turbine checkout, commissioning, and testing will run through the months of September and October 2018.

Q. What approvals and conditions are required under the Asset Purchase Agreement with ACE Wind LLC and Thunder Spirit Wind, LLC?

A. The only approvals needed by Montana-Dakota under the Asset Purchase Agreement with ACE Wind LLC and Thunder Spirit Wind, LLC are the North Dakota Public Service Commission Advance Determination of Prudence and a Certificate of Public Convenience and Necessity, which were received on November 16, 2017 (https://psc.nd.gov/database/documents/17-0268/016-030.pdf), and a FERC 203 approval of the transaction, which was received on August 17, 2018 (https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14-697764).

<u>Transmission Service Charge Recovery</u>

Q. How are MISO and SPP transmission service charges recovered?

A. The MISO and SPP transmission service charges applicable to Montana customers are recovered in base rates today.

Q. How are the MISO and SPP energy market charges recovered?

A. The MISO and SPP energy market charges in Montana are recovered through the Rate 58 Fuel and Purchased Power Cost Tracking Adjustment.

Q. What SPP energy market charges are recovered under Rate 58?

A. Montana-Dakota is required to be an SPP Market Participant associated with the network integrated transmission system (NITS) service that it takes from SPP. The flows to Montana-Dakota’s load and from Montana-Dakota’s generation, in areas taking SPP NITS, are charged SPP market marginal losses and congestion. These SPP marginal losses and congestion are refunded today under Rate 58.

Q. What are the magnitude of the SPP market energy refunds today under Rate 58?

A. Through August 31, 2018, there has been a refund of $3,388,674 for SPP market energy charges to all Montana-Dakota customers; Montana’s share being $908,117and refunded to Rate 58; for marginal losses, congestion, and auction revenue rights (ARRs) assigned to Montana-Dakota. In 2017, these refunds totaled $2,361,103; with Montana’s share being $637,415.

Q. Why is there a net refund in 2017 and 2018 associated with SPP marginal losses, congestion and ARRs.

A. The marginal losses and congestion refunds are a function of Montana-Dakota's nodal SPP price as compared to the MISO-SPP Seam interface price multiplied by the amount of energy flowing to Montana-Dakota's load and from Montana-Dakota's generators that use the SPP transmission service. In addition, Montana-Dakota also receives revenues for ARRs that SPP sells for Montana-Dakota which today flow through Rate 58.

Q. What change are you requesting regarding the recovery mechanism of MISO and SPP transmission service charges?

A. Montana-Dakota believes it would be more appropriate in Montana to recover MISO and SPP transmission service costs and any associated revenue credits associated with these charges under Rate 58 versus continued recovery in base rates. Mr. Travis Jacobson will explain the removal of the transmission service costs from base rates and the amounts proposed to be recovered through Rate 58.

Q. Why do you believe the change in recovery of transmission service to Rate 58 is more appropriate?

A. The MISO and SPP energy market and transmission systems continue to become more interconnected and the costs and benefits of each are more mutually dependent of each other than in the past.

As previously stated, the SPP transmission service charges are producing a significant market benefit for Montana-Dakota's customers associated with the transmission service that it takes. However, the SPP transmission charges are recovered in base rates and the market revenues produced by the transmission service are credited to Rate 58 creating a mismatch today. Both should be charged and credited to Rate 58 going forward so that the market benefit and the transmission charge that created it, can be netted against each other.

Similarly, revenues received for MISO congestion and auction rights, which are assigned to Montana-Dakota based upon MISO transmission service, are also credited to Rate 58 which creates a similar mismatch as the SPP transmission service charges.

Q. What do you mean by the market and transmission systems being more mutually dependent?

A. The low energy costs that Montana-Dakota’s customers benefit from the MISO energy market are directly associated to the transmission service that MISO provides to its members.

In MISO and SPP, customer load is assigned the transmission service charges. Generators are not assigned charges for transmission service. These transmission service charges are directly tied to customer load and are billed based on MW demand or MWh energy billing determinants. Charges associated with transmission service vary with the amount of service (MW or MWh) taken and the qualifying transmission investments recovered in rates. The transmission charges paid by Montana-Dakota under MISO Schedule 26 and 26a and SPP Schedules 9 and 11 are for investments owned by others and recovered under the MISO and SPP transmission tariff and associated schedules.

Q. Can you elaborate more on MISO Schedules 26 and 26A charges?

A. MISO developed the Multi-Value Project (MVP) classification and cost recovery mechanism under Schedule 26A to provide the ability to develop additional renewable energy resources and reduced market congestion which shows up as reduced market energy prices to the benefit of customers. However, the payment for these MVP projects is billed through a MISO Schedule 26A transmission service charge.

Rather than recovering MISO Schedule 26A transmission service charges through base rates, as they are today, these costs would more appropriately be recovered under Rate 58 in Montana where the benefits are received by the customers in the form of lower energy prices.

MISO Schedule 26 projects are cost shared reliability projects or projects which qualify for cost sharing under a MISO postage stamp rate.

A portion of the MISO Schedule 26 charges that Montana-Dakota pays includes the Minnesota CAPEX 2020 projects. These costs vary over time as their annual revenue requirement is updated. MISO Schedule 26 also includes the cost allocation of Market Efficiency Projects (MEPs).

Q. What are Market Efficiency Projects (MEPs)?

A. MEPs are a class of projects, defined to reduce market congestion cost, and recovered by benefiting load through direct allocation or through a system postage stamp which are both recovered through MISO Schedule 26 charges. These projects benefit load through reduced market energy prices. Today they are recovered in base rates but would be more appropriate to recover under Rate 58 going forward.

Q. Is MISO working on any additional transmission initiatives?

A. MISO sees the transmission system moving from a system designed to meet capacity, or peak customer loads, to one that efficiently moves large amounts of energy across the MISO footprint as additional renewables and distributed energy resources are developed. The first of a MISO series of workshops to focus on an energy-based transmission planning approach in addition to capacity-based planning was held on September 7, 2018. https://www.misoenergy.org/events/energy-planning-and-load-shape-forecasting-workshop---september-7-2018/. This approach to transmission planning and recovery of energy delivery investments will continue to support the inclusion of MISO transmission service charges under Rate 58.

Q. Can you elaborate more on SPP Schedule 9 and 11 charges?

A. SPP Schedule 9 is for Network Integrated Transmission Service (NITS) charges which Montana-Dakota began taking from SPP on October 1, 2015 when Western Area Power Administration and Basin Electric joined SPP as a transmission owning member.

SPP Schedule 11 goes along with NITS service as is a recovery of SPP Highway Byway projects which are subregionally and regionally allocated to applicable load.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___

Direct Testimony
of
Tammy J. Nygard

Q. Please state your name, business address and position?

A. Yes. My name is Tammy J. Nygard and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Controller of Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources Group, Inc. I am also the Controller of Cascade Natural Gas Corporation and Intermountain Gas Company; subsidiaries of MDU Resources Group, Inc.

Q. Would you please describe your duties?

A. I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota, Great Plains, Cascade and Intermountain.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 15 years of experience in the utility industry. During my tenure with the MDU Utilities Group, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and now as MDU Utilities Group Controller.

Q. What is the purpose of your testimony in this proceeding?

A. I am responsible for presenting Statement A, Statement B, and Statement F.

Q. Were these statements and the data contained therein prepared by you or under your supervision?

A. Yes, they were.

Q. Are they true to the best of your knowledge and belief?

A. Yes, they are.

Q. Would you describe Statement A and Statement B?

A. Statement A, pages 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2016 and December 31, 2017 with June 30, 2017 and June 30, 2018 information shown on pages 3 and 4, with notes to the financial statements following. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2017 and the six months ended June 30, 2018. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you please explain Statement F?

A. Statement F shows the average utility capital structure of Montana-Dakota for the twelve months ended December 31, 2017 and the projected average capital structure for 2018. Statement F includes the associated costs of debt, preferred stock and common equity. The Company's capital structure supports the rate base of all regulated jurisdictions within Montana-Dakota and Great Plains' service territory. The use of a common capital structure provides economies of scale for debt issues reduces debt issuance costs resulting in lower overall cost of debt. In addition, the Company has one commercial paper program utilized by both the electric and gas segment to better manage the cash flow volatility throughout the year. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.542 percent. The basis for the requested 10.30 percent return on common equity contained within the overall requested rate of return is supported by the testimony of Ms. Ann Bulkley.

Statement F, Rule 38.5.146 summarizes the average of the actual utility capital structure at December 31, 2017 and the pro forma average capital structure and the related utility costs of capital for 2018. As shown on page 1, the components of the 2018 pro forma overall annual rate of return, which are used by Mr. Travis Jacobson to calculate the revenue requirement, are:

	Ratio	Cost	Weighte Cost
Long Term Debt	42.194%	5.055%	2.133%
Short Term Debt 1/	7.358%	2.889%	0.213%
Common Equity	50.448%	10.300%	5.196%
Total	100.000%		7.542%

Page 2 of Rule 38.5.146 reflects the Company's utility common equity balance at December 31, 2017 and the pro forma balance at December 31, 2018. The changes to the common equity balances include the normal changes, including earnings.

Q. How does the Company finance its electric utility operations and determine the amount of common equity, debt and preferred stock to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company has made significant capital expenditures for new plant investment throughout its service territory, including environmental upgrades such as pond modifications at the Lewis & Clark generating station, the Thunder Spirit Wind Farm expansion, as well as transmission upgrades to enhance reliability across the Company's integrated system. These new investments also have associated operating and maintenance costs. Through its financial planning process, the Company determines the amounts of necessary financing required to support these activities. Montana-Dakota finances its operations with a target of 50 percent common equity. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of the Company's short-term credit line and the issuance of additional debt and common equity financing as required to maintain targeted capital ratios and finance the combined utility operations.

The Company did not require any additional common equity in 2017. The Company expects to receive approximately $65.0 million of common equity during 2018 to achieve and maintain the targeted capital structure.

In 2016, the Company issued a $100.0 million private placement of unsecured senior notes with $40.0 million of that amount drawn in 2016 and the balance of $60.0 million delayed until March 2017. The Company is projecting to issue an additional $125.0 million in late 2018, in part to replace the $100.0 million of senior notes which matured and were redeemed in September 2018.

Q. What does Statement F, Rule 38.5.147 show?

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2017 and associated cost of debt, and it shows the pro forma long-term debt and associated costs for 2018, as well as the average cost of debt for the two periods. Page 2 shows the cost and the debt balance by issue at December 31, 2017. Page 3 shows the projected cost and the debt balance by issue at December 31, 2018.

Q. How did you derive the projected cost of debt for 2018?

A. The projected cost of debt for 2018 is based upon the yield-to-maturity of each debt issue outstanding.

Q. Would you please describe Statement F, Rule 38.5.147, page 4 and explain the amortization method utilized?

A. Page 4 reflects the annual amortization of the costs associated with the redemption of long-term debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues. The Company uses the same calculation for accounting purposes.

Q. Would you please describe Statement F, Rule 38.5.147, page 5?

A. Page 5 presents the average short-term debt balance for 2017 and pro forma 2018 as well as the average cost of short-term debt. A twelve-month average of short-term debt is used in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve-month average calculation is more reflective of the borrowing level than a year-end balance.

Q. What does Statement F, Rule 38.5.148 show?

A. Page 1 presents the preferred stock balances at December 31, 2016 and shows all preferred stock issued and outstanding was redeemed on April 1, 2017. Preferred stock comprised about 0.6 percent of the 2017 average capital structure and was replaced with lower cost long-term debt. The redemption reduces the administrative burden associated with the preferred stock and, at the same time, reduces the overall cost of capital. The Company did incur a redemption premium to redeem the preferred stock and has deferred the costs of the redemption. As further discussed in the testimony of Mr. Jacobson, Montana-Dakota has included those costs in the rate base similar to debt redemption costs. The inclusion of deferred preferred stock redemption charges in rate base continues to show a net present value benefit to customers.

Q. Was it prudent to redeem the preferred stock?

A. Yes. By redeeming preferred stock, Montana-Dakota reduced its financing costs. The preferred stock had dividend rates of 4.5% and 4.7%. This was replaced with the fifteen year long-term debt issuance issued in March 2017 at an interest rate of 3.36%. The result of the redemption is a lower overall cost of capital. An analysis has been prepared which demonstrates the overall net benefit of the redemption, inclusive of the rate base impact, is beneficial to customers.

Q. What does Statement F, Rule 38.5.149 show?

A. The schedule presents the issuances of shares of common stock for the five-year period ending December 31, 2017.

Q. What does Statement F, Rule 38.5.150 show?

A. This schedule shows that the Company has not issued shares in connection with a stock split or stock dividend during the five year period ending December 2017.

Q. Would you please describe Statement F, Rule 38.5.151?

A. This schedule presents various financial and market data relative to the Company's common stock for the years ended 2013 through 2017, and for each month of the twelve month period ended December 31, 2017.

Q. Would you please describe Statement F, Rule 38.5.152?

A. This schedule shows the reacquisition of bonds and preferred stock for the 18-month period prior to the date of this filing. All of the issued and outstanding preferred stock was redeemed on April 1, 2017. As discussed earlier, the Company incurred a premium on the redemption of the preferred stock which has been deferred and has been included in the revenue requirement as further discussed by Mr. Jacobson.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit No.___(AEB-1)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

D2018.9.___

PREPARED DIRECT TESTIMONY OF

ANN E. BULKLEY

Q1. Please state your name and business address.

A1. My name is Ann E. Bulkley. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q2. What is your position with Concentric Energy Advisors, Inc. ("Concentric")?

A2. I am employed by Concentric as a Senior Vice President.

Q3. On whose behalf are you submitting this Direct Testimony?

A3. I am submitting this Direct Testimony before the Montana Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q4. Please describe your education and experience.

A4. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No.___(AEB-2), Schedule 1.

Q5. Please describe Concentric's activities in energy and utility engagements.

A5. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q6. Have you testified before any regulatory authorities?

A6. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No.___(AEB-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q7. What is the purpose of your Direct Testimony?

A7. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding Montana-Dakota's return on equity ("ROE")[1] for its Montana electric utility operations and to provide an assessment of the capital

[1] Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "cost of equity".

structure to be used for ratemaking purposes. My analyses and recommendations are supported by the data presented in Exhibit No.___(AEB-2), Schedules 2 through 21, which were prepared by me or under my direction.

Q8. Please provide a brief overview of the analyses that led to your ROE recommendation.

A8. As discussed in more detail in the remainder of my Direct Testimony, it is important to consider the results of several analytical approaches in determining a reasonable recommendation for the Company's ROE. To develop my ROE recommendation, I developed two proxy groups – the Initial Proxy Group and the Refined Proxy Group – that consist of companies that face risk generally comparable to that faced by Montana-Dakota. The Initial Proxy Group includes electric utilities with regulated coal generation representing at least 30 percent of regulated generation capacity. Recognizing that the ROE that is being established in this proceeding is for Montana-Dakota, which has regulated generation capacity that is 50 percent coal generation, I developed the Refined Proxy Group which consists of companies with at least 35% percent of regulated generation capacity that is coal. I applied the Constant Growth and Projected forms of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium Approach. My recommendation also takes into consideration additional risk factors as compared with the Initial Proxy Group: (1) the Company's customer concentration; (2) the Company's small size; (3) Flotation Costs; (4) the Company's capital expenditure requirements; and (5) the regulatory environment in Montana where the Company operates including a comparison of the adjustment mechanisms approved for the Company and the operating subsidiaries of companies in the Initial Proxy Group. Finally, I considered the Company's proposed capital structure as compared to the capital structures of the proxy companies. While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

Q9. How is the remainder of your Direct Testimony organized?

A9. Section II provides a summary of my analyses and conclusions. Section III reviews the regulatory guidelines pertinent to the development of the cost of capital. Section IV discusses current and projected capital market conditions and the effect of those conditions on the Montana-Dakota's cost of equity in Montana. Section V explains my selection of the two proxy groups of electric utilities. Section VI describes my analyses and the analytical basis for the recommendation of the appropriate ROE for Montana-Dakota. Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case. Section VIII discusses the capital structure of the Company as compared with the proxy groups. Section IX presents my conclusions and recommendation for the market cost of equity.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q10. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A10. My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[2] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that result must lead to just and reasonable rates.
- The effect of current and projected capital market conditions on investors' return requirements.
- The Company's regulatory, business, and financial risks relative to the proxy groups of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q11. Please explain how you considered those factors.

A11. I have relied on several analytical approaches to estimate Montana-Dakota's cost of equity based on two proxy groups of publicly traded companies. As shown in Figure 1, those ROE estimation models produce a wide range of results. My conclusion as to where within that range of results for Montana-Dakota's ROE is based on Montana-Dakota's business and financial risk relative to the two proxy groups.

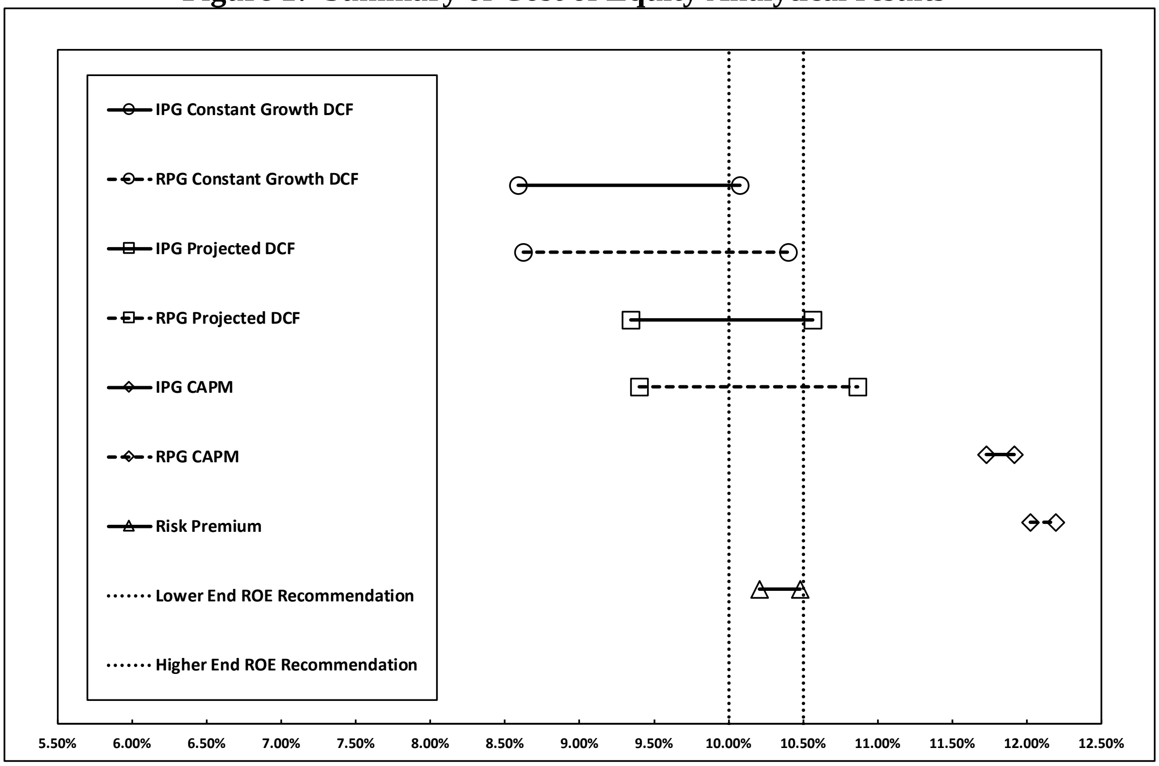
Q12. Please summarize the ROE estimation models that you considered to establish the range of ROEs for Montana-Dakota.

A12. I considered the results of two DCF models: (1) Constant Growth DCF model using current dividends and stock prices; and (2) Constant Growth DCF model developed using Value Line projected dividends and stock prices. In addition, I considered two risk premium approaches: the CAPM and a Bond Yield Plus Risk Premium

2 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

methodology. Figure 1 summarizes the range of results established using each of these estimation methodologies for the Initial and Refined Proxy Groups.

Figure 1: Summary of Cost of Equity Analytical results[3]



As shown on Figure 1 (and in Exhibit No.___(AEB-2), Schedule 2), the range of the DCF model results is wide, particularly in relation to the results of the other methodologies. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results is wide.

The requested ROE is for the future rate period; therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (e.g., projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high

3 The analytical results reflect the results of the Constant Growth and Projected DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

valuations of utility stocks and the market's expectation for higher interest rates. The use of historical inputs and assumptions would tend to understate the required ROE for Montana-Dakota, when considering current and projected conditions in capital markets.

As discussed in more detail in Sections IV and VI, the DCF models are influenced by current market conditions that are not projected to be sustained in the long-term. Those conditions result in lower estimates of the ROE using the DCF model. For example, the 30-day average mean low Constant Growth DCF results[4] (prior to exclusions for outliers) were 8.35 percent for the Initial Proxy Group and 8.55 percent for the Refined Proxy Group, which are below an acceptable range of returns for an electric utility and are below any authorized ROE for an integrated electric utility in the U.S. since at least 1980.[5] Based on prospective capital market conditions, and the inverse relationship between the market risk premium and interest rates, I conclude that the mean low DCF results do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of Montana-Dakota.

Due to these concerns about the results produced by the DCF model, my ROE recommendation considers the mean and mean-high results of the DCF model, a forward-looking CAPM analysis, and a Bond Yield plus Risk Premium analysis. I

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[4] My DCF models generated a mean low, mean, and mean high result. The mean low result is the average of the proxy group DCF results calculated using the lowest earnings growth rate for each company from Value Line, Yahoo! Finance or Zacks.

[5] Source: Regulatory Research Associates, Rate Case History (Integrated Electric Utility) January 1, 1980 – July 31, 2018.

also consider company-specific risk factors and current and prospective capital market conditions.

Q13. What is your recommended ROE for Montana-Dakota?

A13. In addition to the analytical results presented in Figure 1, I also considered the level of regulatory, business, and financial risk faced by Montana-Dakota's electric operations in Montana relative to the proxy groups to establish the range of reasonable returns. Considering these factors, I believe a range from 10.00 to 10.50 percent is reasonable. This recommendation reflects the range of results for the companies in my two proxy groups, the relative risk of Montana-Dakota's electric operations in Montana as compared to the proxy groups, and current capital market conditions. Within that range, a return of 10.30 percent is reasonable.

Q14. Please summarize the analysis you conducted in determining that Montana-Dakota's requested capital structure is reasonable and appropriate.

A14. I reviewed the capital structures of the utility subsidiaries of the proxy companies in my Initial and Refined Proxy Groups for the eight quarters ending with the first quarter of 2018 to determine if Montana-Dakota's requested capital structure was reasonable. As shown in Exhibit No.___(AEB-2), Schedules 20 and 21, the results of that analysis demonstrate that the average equity ratios range from 45.32 percent to 58.56 percent for the utility operating companies of the Initial Proxy Group and 47.49 percent to 58.56 percent for the utility operating companies of the Refined Proxy Group. Montana-Dakota's proposed equity ratio of 50.45 percent is in the middle of the range produced by the proxy groups and therefore, is reasonable, especially since Federal tax reform legislation has had a negative effect on the cash flows and credit metrics of regulated utilities.

III. REGULATORY GUIDELINES

Q15. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A15. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[6]

Q16. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A16. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric service while maintaining its financial integrity. To the extent the Company is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

[6] Hope, 320 U.S. 591 (1944); Bluefield, 262 U.S. 679 (1923).

Q17. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A17. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other natural gas and electric utilities can inhibit the utility's ability to attract capital for investment in Montana.

Likewise, because Montana-Dakota is a Division of MDU Resources Group, Inc. ("MDU Resources"), Montana-Dakota competes with the other MDU Resources subsidiaries for investment capital. In determining how to allocate its finite capital resources, it would be reasonable for MDU Resources to consider the authorized ROE of each of its subsidiaries.

Q18. What are your conclusions regarding regulatory guidelines?

A18. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions; doing so balances the long-term interests of the utility and its ratepayers.

The financial community carefully monitors the current and expected financial condition of utility companies, and the regulatory framework in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Commission's order in this proceeding, therefore, should establish rates that provide Montana-Dakota with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms under a variety of economic and financial market conditions; (2) sufficient to ensure good management and its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. To the extent Montana-Dakota is authorized the opportunity to earn its market-based cost of capital, the proper balance is achieved between customers' and shareholders' interests.

IV. CAPITAL MARKET CONDITIONS

Q19. Why is it important to analyze capital market conditions?

A19. The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates in the ROE estimation models to estimate the required return for the subject company.

As is discussed in the remainder of this section, analysts and regulatory commissions have concluded that current market conditions are anomalous and that these conditions have affected the results of the ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q20. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A20. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) the current low interest rate environment and the corresponding effect on valuations and dividend yields of utility stocks relative to historical levels; (2) the market's expectation for higher interest rates; and (3) recent Federal tax reform. In this section, I discuss each of these factors and how they affect the models used to estimate the cost of equity for regulated utilities.

A. The Effect of Market Conditions on Valuations

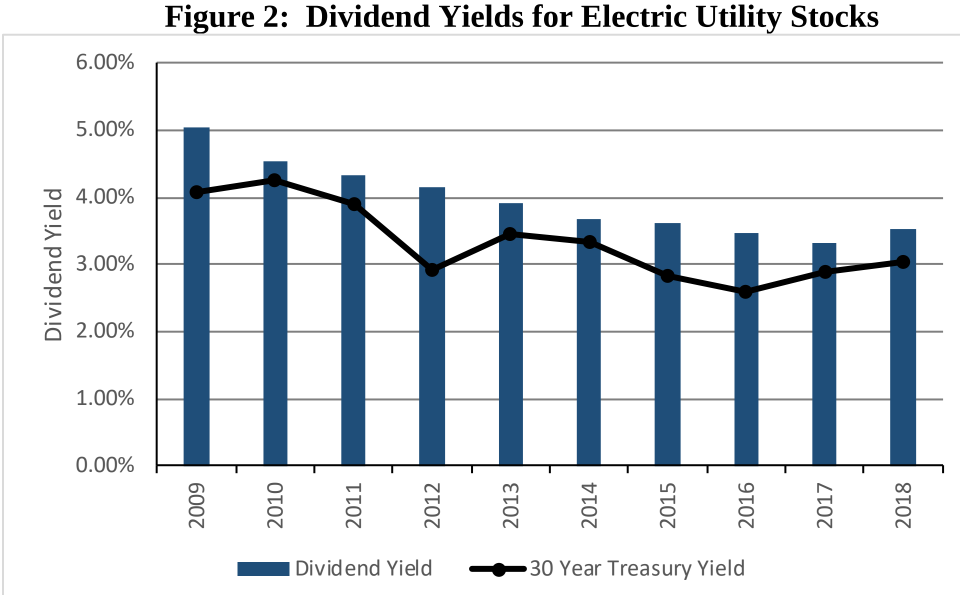
Q21. How has the Federal Reserve's monetary policy affected capital markets in recent years?

A21. Extraordinary and persistent federal intervention in capital markets artificially lowered government bond yields after the Great Recession of 2008-2009, as the Federal Open Market Committee ("FOMC") used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage-backed securities) to stimulate the U.S. economy. As a result of very low or zero returns on short-term government bonds, yield-seeking investors have been forced into longer-term instruments, bidding up prices and reducing yields on those investments. As investors have moved along the risk spectrum in search of yields that meet their return requirements, there has been increased demand for dividend-paying equities, such as electric and gas utility stocks.

Q22. How has the period of abnormally low interest rates affected the valuations and dividend yields of utility shares?

A22. The Federal Reserve's accommodative monetary policy has caused investors to seek alternatives to the historically low interest rates available on Treasury bonds. A result of this search for higher yield is that the share prices for many common stocks, especially dividend-paying stocks such as utilities, have been driven higher while the dividend yields (which are computed by dividing the dividend payment by the stock price) have decreased to levels well below the historical average. As shown in Figure 2, over the period from 2009 through 2017, since the Federal Reserve intervened to stabilize financial markets and support the economic recovery after the Great Recession of 2008-09, Treasury bond yields and utility dividend yields declined. Specifically, Treasury bond yields declined by approximately 118 basis points, and electric utility dividend yields have decreased by about 172 basis points over this same period. In 2018 however, both Treasury bond yields and dividend yields have been increasing. As of July 31, 2018, the yield on 30-year Treasury bonds was 3.05 percent and dividend yields had increased approximately 19 basis points from the end-of-year 2017 level of 3.32 percent to 3.51 percent. It is important to note that while there has been a slight increase in 2018, dividend yields are still below their historical average over the past decade.

Figure 2: Dividend Yields for Electric Utility Stocks



Note: Figure includes 2018 data through July 31, 2018.
Source: SNL Financial

Q23. How have higher stock valuations and lower dividend yields for utility companies affected the results of the DCF model?

A23. During periods of general economic and capital market stability, the DCF model may adequately reflect market conditions and investor expectations. However, in the current market environment, the DCF model results are distorted by the historically low level of interest rates and the higher valuation of utility stocks. Value Line recently commented on the high valuations of electric utilities:

> Following a stellar showing (for most electric utility stocks) in 2017, the group has turned in a mixed performance in 2018. Most equities have risen or fallen modestly since the start of the year. For several months, the market has expected the Federal Reserve to raise interest rates, and this is coming to fruition. This has a negative effect on the prices of utility equities. However, some stocks have fared well for company-specific reasons. We mentioned takeover speculation above. In addition, the price of Sempra surged after two investors (with a combined 4.9% ownership interest) pushed the company to make changes intended to unlock shareholder value. We note that most of these equities have recent quotations within (or even above) their 2021-2023 Target Price Range. This indicates that most utility issues are still priced expensively. The industry mean for the dividend yield is just 3.4%, and the average 3- to 5-year total return potential is only 4%.[7]

This is further supported by a recent Edward Jones report on the utility sector:

> Utility valuations have come down as 10-year Treasury bond rates have climbed back near 3%. On a price-to-earnings basis, they remain significantly above their historical average, but have declined to less unreasonable levels. We have seen utility valuations moving in line with interest rate movements, although there have been exceptions to this. Overall, however, we believe the low-interest-rate environment has been the biggest factor in pushing

[7] Value Line Investment Survey, Electric Utility (West) Industry, July 27, 2018, at 2219.

> utilities higher since many investors buy them for their dividend yield.
>
> Utilities have declined more than 10% from their all-time highs reached late in 2017, but are still trading significantly above their average price-to-earnings ratio over the past decade. The premium valuation continues to reflect not only the low interest rate environment, but also the stable and predominantly regulated earnings growth we foresee.[8]

As noted by Value Line and Edward Jones, over the last few years, utility stocks have experienced high valuations and low dividend yields; however, those dynamics are changing. Value Line and Edward Jones recognize that as interest rates increase, bonds become a substitute for utility stocks. This change in market conditions implies that the ROE calculated using historical market data in the DCF model may understate the forward-looking cost of equity.

Q24. How did the Standard & Poor's Utilities Index respond to the market conditions that existed following the Great Recession of 2008-2009?

A24. Figure 3 demonstrates market conditions from 2007-2018 as measured by the S&P Utilities Index and the yield on 30-year Treasury bonds. As shown in Figure 3, the S&P Utilities Index increased steadily from the beginning of 2009 through early November 2017, as yields on 30-year Treasury bonds declined in response to accommodative federal monetary policy.

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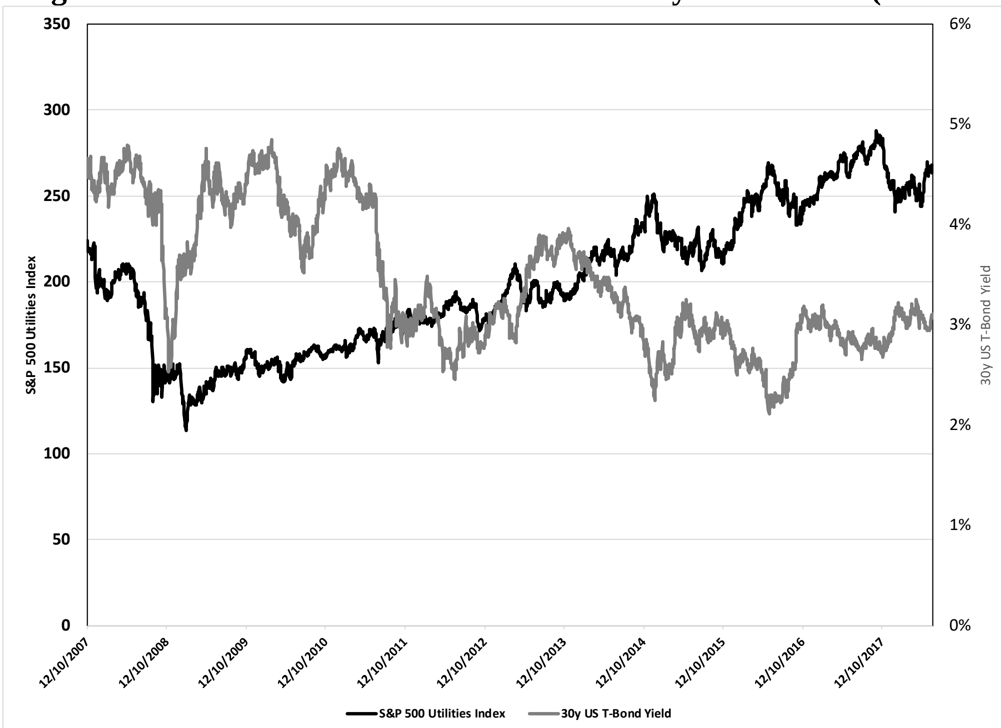
8 Andy Pusateri and Andy Smith. Edward Jones, Utilities Sector Outlook (June 8, 2018), at 2-3. [Reference to figure omitted.]

Figure 3: S&P Utilities Index and U.S. Treasury Bond Yields (2007-2018)



Source: SNL Financial

Q25. In 2018, have utility stock prices remained at the same levels that were experienced in 2017?

A25. No. Recent market conditions, however, have been considerably different. Responding to changes in Federal tax reform and interest rates, since the House of Representatives approved the initial version of the tax reform legislation on November 16, 2017, the S&P Utilities Index has declined by approximately 6 percent, as yields on 30-year Treasury bonds have increased from 2.81 percent to 3.08 percent.[9] This change in stock valuations will affect the dividend yield in the DCF model. Furthermore, dividend yields that are based on the historical higher stock prices are likely understating the forward-looking cost of equity for utility

[9] Comparison as of July 31, 2018.

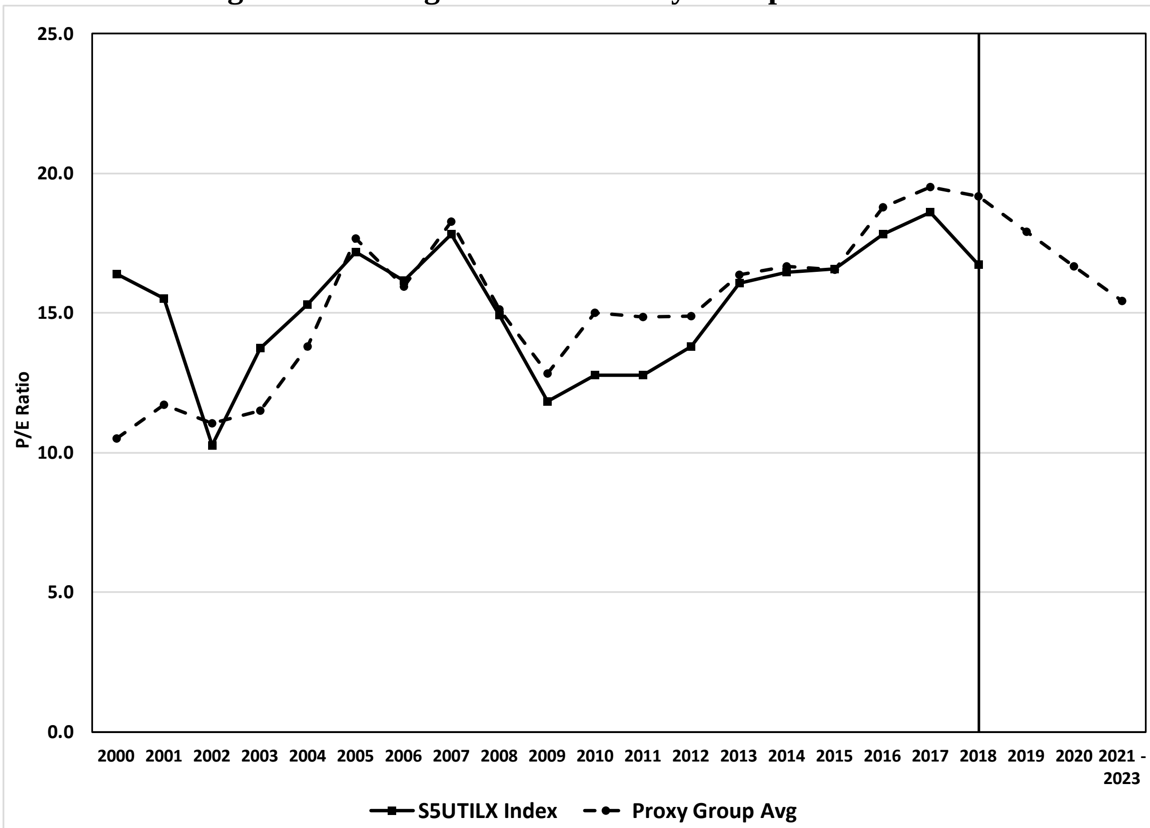
companies. The effect of tax reform in determining the cost of equity for Montana-Dakota is discussed in more detail later in my testimony.

Figure 4 summarizes the average historical and projected P/E ratios for the companies in the Initial Proxy Group[10] calculated using data from Bloomberg Professional and Value Line.[11] As shown in Figure 4, the average P/E ratio for the proxy companies was higher in 2017 than at any other time in the last seventeen years and is significantly higher than the average projected P/E ratio for the group for the period from 2021-2023. In 2018 however, the average P/E ratio for the proxy companies has decreased slightly to 19.17 from the high in 2017 of 19.52. All else equal, if P/E ratios for the proxy companies continue to decline, as Value Line projects, the ROE results from the DCF model would be higher. Therefore, the DCF model is likely understating the forward-looking cost of equity for the proxy group companies.

[10] The Initial Proxy Group was used since the Refined Proxy Group is a subset of the Initial Proxy Group.

[11] Selection of the Proxy Companies is discussed in detail in Section V of my Testimony.

Figure 4: Average Historical Proxy Group P/E Ratios



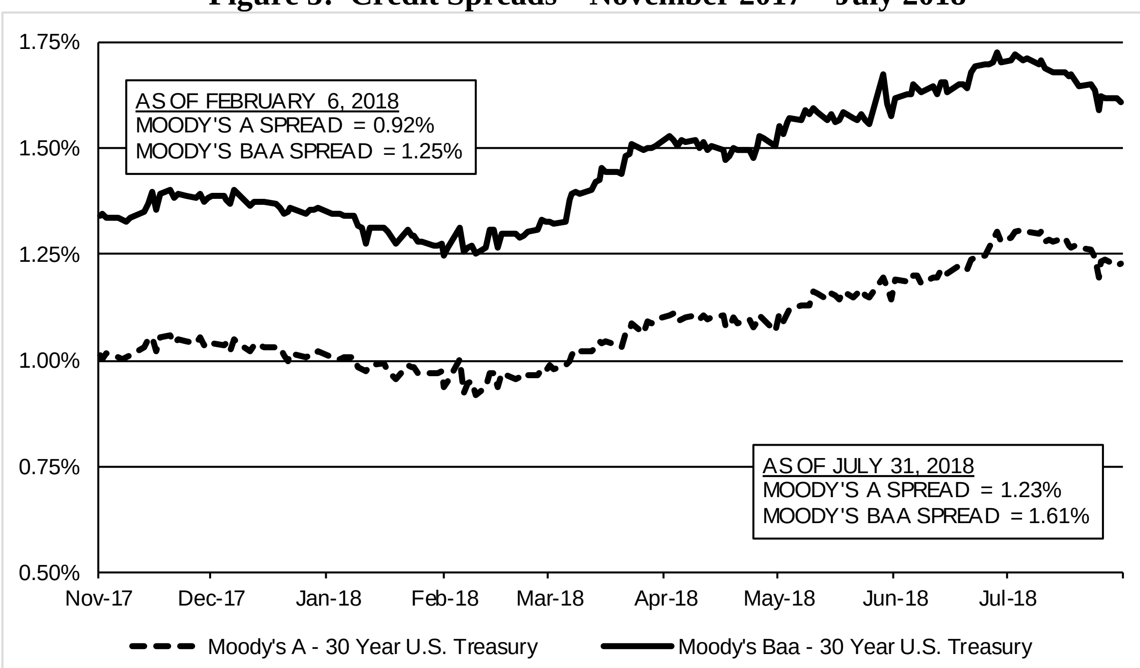
Note: Figure includes data through July 31, 2018.
Source: Bloomberg Professional

Q26. Are there other indications that market conditions have changed in 2018?

A26. Yes, there is evidence that investors' risk sentiment has increased. As shown in Figure 5, credit spreads between Treasury bonds and utility bonds have increased since February 2018 which was the lowest level credit spreads have been since prior to the Great Recession of 2008-2009. In fact, since credit spreads reached a low point on February 6, 2018, the spread between Baa-rated utility debt and Treasury bonds has increased 35 basis points, while the spread between A-rated utility debt and Treasury bonds has increased 30 basis points. This indicates that investors are requiring a higher risk premium to compensate them for the additional credit risk associated with lower-rated utility debt. The higher required risk premium is the result of increased uncertainty in the market which has reduced investor confidence. As Bloomberg notes:

> Corporate bond spreads have been widening since February, when they reached the tightest since before the financial crisis. Fewer foreign buyers, rate volatility and trade tensions are chipping away at investor confidence in the U.S. market, according to Thomas Murphy, a portfolio manager at Columbia Threadneedle Investments in Minneapolis.
>
> "A lot of people pushed into our market because of QE overseas. They can now go back to their home markets. Hedging costs have gone up dramatically," said Murphy, whose firm has about $172 billion of fixed-income assets under management. There are also "concerns about rate volatility and concerns on the curve shape changing," he added.[12]

Figure 5: Credit Spreads – November 2017 – July 2018



Source: Bloomberg Professional

[12] Hagan, Shelly. "Corporate Bond Spreads Jump to 16-Month High." Bloomberg.com, Bloomberg, 22 June 2018, www.bloomberg.com/news/articles/2018-06-22/corporate-bond-spreads-jump-to-16-month-high-amid-growing-supply.

Q27. How do equity investors view the utilities sector based on these recent market conditions?

A27. Investment advisors have suggested that utility stocks may underperform as a result of market conditions. Charles Schwab recently provided guidance on the utilities sector.

> The utility sector received a boost recently as investors moved into defensive sectors as concerns over global growth were exacerbated by the ramping up of trade rhetoric. We believe that this is a temporary phenomenon and that lagging performance will re-emerge as rising inflationary pressures should push fixed income yields higher again, lessening the attractiveness of the utilities sector, causing the sector's prospects to again dim. **We have warned against using equity dividends as a proxy for bond yield income, as the risk characteristics are much different. We believe investors should refrain from rushing into the utilities sector, as we could see a repeat of the sharp reversals we've seen recently.**
>
> We think U.S. economic data will continue to show improvement, prompting investors to move into more cyclical areas of the market, away from the traditionally defensive utilities sector. Inflation readings have perked up, with the Consumer Price Index moving up to a 2.8% year-over-year rise, not extreme, certainly, but the trend is higher, while wages also are moving higher, with the Labor Department's average hourly earnings number posting a 2.6% year-over-year gain. The result has been fixed income rates moving higher, a trend we believe will generally continue, leading to a movement away from utilities.[13]

This view was further supported by Merrill Lynch who noted that:

> With respective dividend yields of 5.7%, 3.7% and 3.1%, the telecoms, utilities and consumer staples sectors have been the three lowest-returning sectors this year. All three are likely to come under increased competition from rising interest rates as the Fed tightens

[13] Sorensen, Brad, "Utilities Sector Rating: Underperform", Charles Schwab, August 2, 2018. (Emphasis added.)

> further, and bond yields breach 3% beyond 10-year maturities for the first time since 2011.
>
> For utilities and telecoms in particular, we also see a range of structural headwinds continuing to weigh on returns. Mature residential electricity sales and increasing energy efficiency continue to limit the revenue growth potential for the utilities sector, with cost headwinds coming from a range of sources. These include the need to replace existing grid infrastructure such as poles and wires, and required investment in cleaner generating capacity at the state level, even as the Environmental Protection Agency (EPA) pushes to loosen federal regulations. The falling cost of renewables and growing competition from distributed power generation should also have a negative impact on traditional utilities as costs are spread over a dwindling base of household rate payers.[14]

Q28. Have regulators recently responded to the historically low dividend yields for utility companies and the corresponding effect on the DCF model?

A28. Yes. As I discuss in more detail later in my testimony, the Federal Energy Regulatory Commission ("FERC") has determined that anomalous capital market conditions have caused the DCF model to understate equity costs for regulated utilities at this time.[15]

In addition, the Illinois Commerce Commission ("ICC"), the Pennsylvania Public Utility Commission ("PPUC"), the Massachusetts Department of Public Utilities ("MDPU"), and the Missouri Public Service Commission ("Missouri PSC") have all considered this in recent decisions. I discuss the response of these regulators to historically low dividend yields and the impact on the DCF model in detail later in

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14 Merrill Lynch Chief Investment Office, "Capital Market Outlook", May 29, 2018, at 5.

15 FERC Docket No. EL11-66-001, Opinion No. 531, footnote 286. While Opinion No. 531 was recently remanded to the FERC by the D.C. Circuit Court on other grounds, that decision did not question the finding by the FERC that capital market conditions were anomalous. Additionally, the methodologies that were relied on by FERC to establish the range have not be challenged.

my testimony.

B. The Current and Expected Interest Rate Environment

Q29. What evidence is there that the interest rate environment is shifting?

A29. Based on stronger conditions in employment markets, a relatively stable inflation rate, steady economic growth, and increased household spending, the Federal Reserve raised the short-term borrowing rate by 25 basis points at both the March and June 2018 meetings. Since December 2015, the Federal Reserve has increased interest rates seven times, bringing the federal funds rate to the range of 1.75 percent to 2.00 percent. As the economy continues to expand, the Federal Reserve is expected to continue increasing short-term interest rates to sustain the desired balance between unemployment and consumer price inflation.[16] The Federal Reserve has indicated that it intends to raise short-term rates twice more in 2018.[17]

Furthermore, in October 2017, the Federal Open Market Committee ("FOMC") started reducing the size of the Fed's $4.5 trillion bond portfolio by no longer reinvesting the proceeds of the bonds it holds. In response to the Great Recession, the Fed pursued a policy known as "Quantitative Easing," in which it systematically purchased mortgage-backed securities and long-term Treasury bonds to provide liquidity in financial markets and drive down yields on long-term government bonds. Although the Federal Reserve discontinued the Quantitative Easing program in October 2014, it continued to reinvest the proceeds from the bonds it

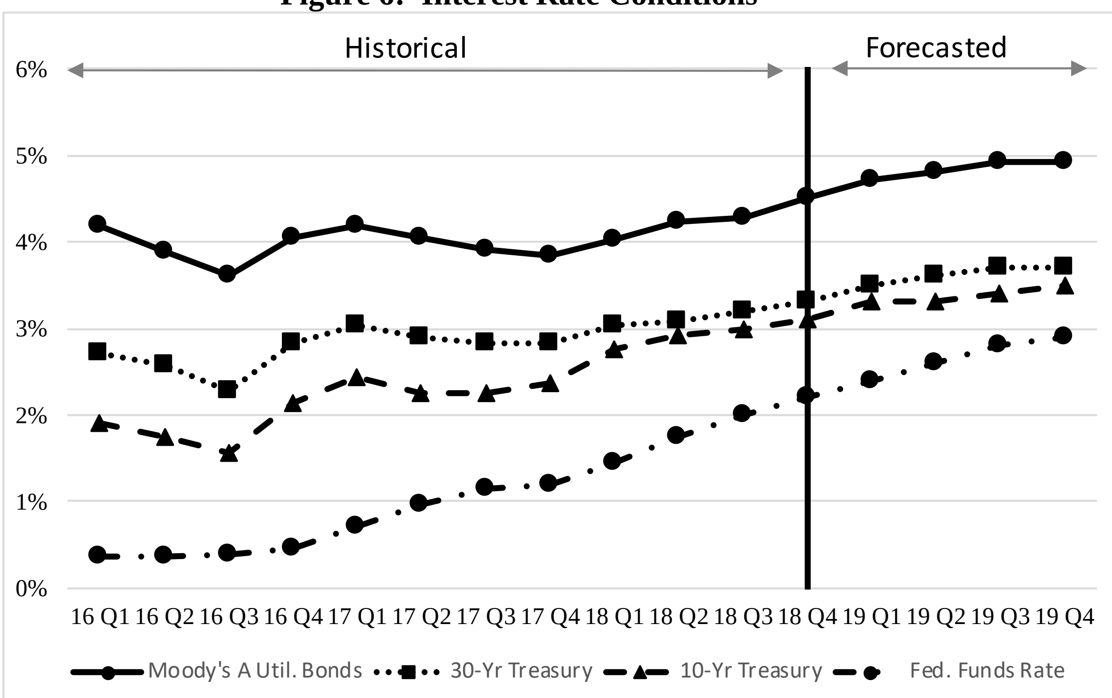
16 FOMC, Federal Reserve press release, August 1, 2018.

17 Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, June 2018.

holds. Under the new policy, the FOMC intends to gradually reduce the Federal Reserve's securities holdings by $10 billion per month initially, ramping up to $50 billion per month by the end of the first twelve months.[18] The Federal Reserve's announced unwinding plan provides additional support for investors' view that long-term interest rates will increase, as the Federal Reserve gradually reverses the Quantitative Easing program that reduced those long-term rates.

Investors are expecting continued increases in interest rates on both government and corporate/utility bonds over the next few years, as shown in Figure 6.

Figure 6: Interest Rate Conditions[19]



18 Federal Reserve press release, Addendum to the Policy Normalization Principles and Plans, June 14, 2017, implemented at FOMC meeting September 20, 2017.

19 Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume. 37, No. 8, August 1, 2018 at 2.

The context for setting the authorized ROE for Montana-Dakota should not be the low interest rate environment of the last few years. Rather, the Commission should consider recent evidence that interest rates have been increasing, and that capital costs over the period that rates will be in effect are expected to continue to increase as the Federal Reserve normalizes monetary policy and as the effects of the Tax Cuts and Jobs Act ("TCJA"), which is discussed later in my Testimony, flow through the economy.

Q30. Did the Commission consider capital market conditions when it issued its last decision for Montana-Dakota?

A30. Yes. The Commission's Order in Montana-Dakota's last rate case, Docket No. D2015.6.51, was issued on March 25, 2016 which approved the settlement agreement filed by the parties in the rate case. While the settlement agreement was silent with respect to the ROE, the Commission noted that capital market conditions had changed drastically since the Commission last authorized an ROE for Montana-Dakota in Docket No. 2007.7.79 and indicated that it was appropriate to provide guidance regarding a reasonable ROE range.[20] Based on the evidence in the record, the Commission deemed an ROE range of 9.00 percent to 9.50 percent as appropriate but also recognized that market conditions could change again by the time another rate case is filed.[21]

[20] Docket No. D2015.6.51, Order Mo. 7433f, IN THE MATTER OF THE Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service in the State of Montana (Mar. 25, 2016), at 5.

[21] *Id.*, at 8.

Q31. How do current interest rates compare to rates when the Commission issued its last decision for Montana-Dakota?

A31. As noted above, the Commission approved the settlement agreement in Montana-Dakota's last rate case on March 25, 2016. Figure 7 compares the interest rates on government and A-rated utility bonds in March 2016 to those in July 2018.

Figure 7: Interest Rate Comparison[22]

	March 2016	July 2018	Change
10-year Treasury	1.84%	2.89%	+1.05%
30-year Treasury	2.66%	3.01%	+0.35%
Moody's A Utility Bond	4.15%	4.27%	+0.12%

As shown in Figure 7, average yields on 10-year Treasury bonds were substantially higher in July 2018 than in March 2016, while yields on 30-year Treasury bonds and Moody's A-rated Utility bonds were somewhat higher. Based on the increase in Treasury bond yields since the Commission issued its guidance on a reasonable ROE range of 9.00 percent to 9.50 percent, it is clear that the cost of capital has increased since the settlement agreement was approved by the Commission in March 2016. In summary, current and prospective capital market conditions support an authorized ROE for Montana-Dakota that is higher than the high-end of the Commission's ROE range of 9.50 percent.

Q32. What effect do rising interest rates have on the cost of equity?

A32. As interest rates continue to increase, the cost of equity for the proxy companies using the DCF model is likely to be an overly conservative estimate of investors' required returns because the proxy group average dividend yield reflects the

22 Source: Bloomberg Professional. All values are based on 30-day average yields.

increase in stock prices that resulted from substantially lower interest rates. As such, rising interest rates support the selection of a return toward the upper end of a reasonable range of ROE estimates resulting from the DCF analysis. Alternatively, my CAPM and Bond Yield Plus Risk Premium analyses include estimated returns based on near-term projected interest rates, reflecting investors' expectations of market conditions over the period that the rates that are determined in this case will be set.

C. Effect of Tax Reform on the Return on Equity and Capital Structure

Q33. Are there other factors that should be considered in determining the cost of equity for Montana-Dakota?

A33. Yes. The effect of the recently passed TCJA should also be considered in the determination of the cost of equity. The credit rating agencies have commented on the effect of the TCJA on regulated utilities. In summary, the TCJA is expected to reduce utility revenues due to the lower federal income taxes and the requirement to return excess accumulated deferred income taxes. This change in revenue is expected to reduce funds from operations ("FFO") metrics across the sector, and absent regulatory mitigation strategies, is expected to lead to weaker credit metrics and negative ratings actions for some utilities.[23]

[23] FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.

Q34. Have credit or equity analysts commented on the effect of the TCJA on Utilities?

A34. Yes. Moody's Investors Services ("Moody's") provided a summary of the implications of the TCJA for investor-owned utilities. In that summary Moody's indicated that while the TCJA was credit positive for many sectors, it has an overall negative credit impact on regulated operating companies of utilities and their holding companies due to the reduction in cash flow metrics that results from the change the federal tax rate and the loss of bonus depreciation.

Moody's acknowledged that the rates that regulators allow utilities to charge customers is based on a cost-plus model, with tax expense being one of the pass-through items. Utilities will collect less taxes at the lower rate, reducing revenue. While the taxes are ultimately paid out as an expense, under the new law utilities lose the timing benefit, reducing cash that may have been carried over a number of years. The lower tax rate combined with the loss of bonus depreciation will have a negative effect on utility cash flows and will ultimately negatively impact the utilities' ability to fund ongoing operations and capital improvement programs.

Q35. How has Moody's responded to the increased risk for utilities resulting from the TCJA?

A35. In January 2018, Moody's issued a report changing the rating outlook for several regulated utilities from Stable to Negative.[24] At that time, Moody's noted that the rating change affected companies with limited cushion in their ratings for

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[24] Moody's Investor Service, Global Credit Research, Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform, January 19, 2018.

deterioration in financial performance. In June 2018, Moody's issued a report in which the rating agency downgraded the outlook for the entire regulated utility industry from stable to negative for the first time ever. Moody's cites ongoing concerns about the negative effect of the TCJA on cash flows of regulated utilities. While noting that "[r]egulatory commissions and utility management teams are taking important first steps"[25] and that "we have seen some credit positive developments in some states in response to tax reform,"[26] Moody's concludes that "we believe that it will take longer than 12-18 months for the majority of the sector to show any material financial improvement from such efforts."[27]

Q36. What does it mean for Moody's to downgrade a credit outlook?

A36. A Moody's rating outlook is an opinion regarding the likely rating direction over what it refers to as "the medium term." A Stable outlook indicates a low likelihood of a rating change in the medium term. A Negative outlook indicates a higher likelihood of a rating change over the medium term. While Moody's indicates that the time period for changing a rating subsequent to a change in the outlook form Stable will vary, on average, Moody's indicates that a rating change will follow within a year of a change in outlook.[28]

25 Moody's Investors Service, "Regulated utilities – US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage", June 18, 2018, at 3.
26 *Ibid.*
27 *Ibid.*
28 Moody's Investors Service, Rating Symbols and Definitions, July 2017, at 27.

Q37. Have other rating agencies commented on the effect of the Act on ratings?

A37. Yes. Standard and Poor's ("S&P") published a report on January 24, 2018 entitled "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound" in which S&P concludes:

> The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.
>
> Finally, if the regulatory response does not adequately compensate for the lower cash flows, we will look to the issuers, especially at the holding company level, to take steps to protect credit metrics if necessary. Some deterioration in the ability to deduct interest expense could occur at the parent, making debt there relatively more expensive. More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates. It will probably take the remainder of this year to fully assess the financial impact on each issuer from the change in tax liabilities, the regulatory response, and the company's ultimate response. We have already witnessed differing responses. We revised our outlook to negative on PNM Resources Inc. and its subsidiaries on Jan. 16 after a Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows. It remains to be seen whether PNM will eventually do so, especially as it is facing other regulatory headwinds. On the other hand, FirstEnergy Corp. issued $1.62 billion of mandatory convertible stock and $850 million of common equity on Jan. 22 and explicitly referenced the need to support its credit metrics in the face of the

> new tax code in announcing the move. That is exactly the kind of proactive financial management that we will be looking for to fortify credit quality and promote ratings stability.[29]

Q38. What conclusions do you draw from your analysis of capital market conditions?

A38. The important conclusions resulting from capital market conditions are:

- The assumptions used in the ROE estimation models have been affected by anomalous market conditions.
- Recent market conditions are not expected to persist as the Federal Reserve continues to normalize monetary policy. As a result, the recent historical market conditions are not reflective of the market conditions that will be present when the rates for Montana-Dakota will be in effect.
- It is important to consider the results of a variety of ROE estimation models, using forward-looking assumptions to estimate the cost of equity.
- Without adequate regulatory support, the TCJA will have a negative effect on utility cash flows, which increases investor risk expectations for utilities.

[29] Standard and Poor's Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," January 24, 2018.

V. PROXY GROUP SELECTION

Q39. Why have you used a group of proxy companies to estimate the cost of equity for Montana-Dakota?

A39. In this proceeding, we are focused on estimating the cost of equity for an electric utility that is not itself publicly traded. Since the cost of equity is a market-based concept and given that Montana-Dakota's Montana electric operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to Montana-Dakota in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if Montana-Dakota were a publicly-traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for Montana-Dakota.

Q40. Please provide a brief profile of Montana-Dakota in Montana.

A40. Montana-Dakota is an electric utility that is a division of MDU Resources. The Company provides electric utility service to approximately 25,724 customers in 30 communities in Montana.[30] Montana-Dakota's electric rate base in Montana in 2017 was approximately $191 million.[31] In addition, Montana-Dakota had electric operating revenues in 2017 (the most current data available) of approximately $60.1 million, made up of 28.46 percent residential, 17.36 percent commercial (i.e., small general service), 51.72 percent industrial (i.e., large general service), and the remainder for lighting and municipal pumping.[32] Furthermore, Montana-Dakota's electric operations in Montana represented 20 percent of Montana-Dakota's electric retail revenue in 2017.[33] Montana-Dakota's electric operations in Montana are a part of Montana-Dakota's integrated electric system which also includes Montana-Dakota's electric operations in North Dakota and South Dakota while Montana-Dakota's electric operations in Wyoming are included in its Sheridan system. In 2017, approximately 73 percent of Montana-Dakota's net generation needs were satisfied by its owned and joint owned facilities while the remaining 27 percent was purchased power.[34] Additionally, approximately 76 percent of the energy generated by Montana-Dakota and approximately 50 percent of its owned generation capacity came from coal-fired power plants in 2017.[35] MDU Resources, of which Montana-Dakota is a division, currently has an investment

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[30] Montana-Dakota Utilities, 2017 Annual Report to the Montana Public Service Commission, at 33.
[31] Data provided by Montana-Dakota.
[32] Montana-Dakota Utilities, 2017 Annual Report to the Montana Public Service Commission, at 41.
[33] MDU Resources Group, Inc., U.S. Securities and Exchange Commission Form 10-K, December 31, 2017, at 8.
[34] Data provided by Montana-Dakota.
[35] MDU Resources Group, Inc., U.S. Securities and Exchange Commission Form 10-K, December 31, 2017, at 24.

grade long-term rating of BBB+ (Outlook: Stable) from Standard and Poor's and BBB+ (Outlook: Stable) from Fitch.[36]

Q41. How did you select the companies included in your Initial Proxy Group?

A41. I began with the group of 40 companies that Value Line classifies as Electric Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- own regulated generation assets that are included in rate base;
- have more than 30 percent of owned regulated generation capacity come from regulated coal-fired power plants;
- derive more than 70 percent of their total operating income from regulated operations;
- derive more than 80 percent of their total regulated operating income from regulated electric operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q42. What is the composition of your Initial Proxy Group?

A42. My Initial Proxy Group consists of the companies shown in Figure 8 below.

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[36] S&P Global Ratings Research Summary: MDU Resources Group Inc., (December 27, 2076); FitchRatings, Fitch Affirms MDU Resources, Centennial Energy and Cascade; Outlook Stable, (June 23, 2017).

Figure 8: Initial Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
DTE Energy Company	DTE
Duke Energy Corporation	DUK
FirstEnergy Corporation	FE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
PNM Resources, Inc.	PNM
PPL Corporation	PPL
Xcel Energy Inc.	XEL

Q43. Did you consider additional proxy groups?

A43. Yes, I did. As discussed above, approximately 50 percent of Montana-Dakota's owned generation capacity came from coal-fired power plants. While my Initial Proxy Group includes only companies with at least 30 percent of regulated owned generation capacity from coal-fired power plants, the group still includes companies with far less coal capacity than Montana-Dakota. In general, utilities with generation that is heavily weighted toward one fuel source face greater risks that adverse circumstances will arise that render much of their generating capacity uneconomic. For example, increased environmental regulations aimed at cutting power plant emissions pose additional business risk as sizable future capital expenditures may be required to comply with regulations. While the Trump Administration repealed the Clean Power Plan of the Obama Administration, there is still much uncertainty regarding the future of environmental regulations for coal power plants. This is especially true as coal generation faces increased competition from natural gas as a result of low natural gas prices and renewable generation due to various subsidies and mandates for renewable generating technologies. These changes could weigh heavily on companies like Montana-Dakota that own a significant amount of coal-fired generation assets. In fact, as discussed in the Direct Testimony of Mr. Skabo, Montana-Dakota expects to retire three coal plants in 2025 (i.e., Heskett I, Heskett II, and Lewis & Clark). Additionally, the 2017 Integrated Resource Plan filed by Montana-Dakota with the Commission does not currently consider new coal-fired baseload generation as a feasible solution for future capacity and energy resource needs.[37] As a result, I also considered a Refined Proxy Group that includes companies with a higher percentage of owned regulated generation capacity from coal-fired plants.

Q44. How did you select the companies included in your Refined Proxy Group?

A44. I started by relying on many of the screening criteria used to develop the Initial Proxy Group. In developing this more refined group, I increased the percentage of coal-fired generation to 35 percent to more closely reflect Montana-Dakota's operations.

Q45. What is the composition of your Refined Proxy Group?

A45. The additional coal-fired generation requirement reduced the size of the proxy group from thirteen to nine companies, shown in Figure 9 below.

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[37] Montana-Dakota Utilities Co., 2017 Integrated Resource Plan Submitted to the Montana Public Service Commission, September 15, 2017, at 33.

Figure 9: Refined Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
DTE Energy Company	DTE
FirstEnergy Corporation	FE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
PPL Corporation	PPL

Q46. Is a proxy group of nine companies a reasonable size to estimate the cost of equity?

A46. While I recognize that the Refined Proxy Group includes fewer companies, it is still a reasonable size to use to estimate the cost of equity. In addition, this proxy group more closely reflects Montana-Dakota's operations due to the higher percentage of coal-fired generation (Montana-Dakota's generation portfolio is 50 percent coal-fired generation). Therefore, I have considered the range of results established using both the Refined Proxy Group and the Initial Proxy Group.

VI. COST OF EQUITY ESTIMATION

Q47. Please briefly discuss the ROE in the context of the regulated rate of return.

A47. The overall rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q48. How is the required ROE determined?

A48. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the Company's cost of equity falls within the range of results. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q49. What methods did you use to determine the Company's ROE?

A49. I considered the results of the Constant Growth DCF model, a Projected Constant Growth DCF model, the CAPM model, and the Bond Yield Plus Risk Premium methodology. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q50. Why is it important to use more than one analytical approach?

A50. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as can reasonably be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[38] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[39] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q51. Is it important given the current market conditions to use more than one analytical approach?

A51. Yes. As discussed in Section IV above, the U.S. economy is beginning to emerge from an unprecedented period of low interest rates. Low interest rates, and the effects of the investor "flight to quality" can be seen in high utility share valuations, relative to historical levels and relative to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity estimates from a DCF analysis. Low interest rates also impact the CAPM in two ways: (1) the risk-free rate is lower, and (2) because the market risk premium is a function of interest rates, (i.e., it is the return on the broad stock market less the risk-free interest rate), the risk premium should move higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE

[38] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[39] Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

estimates for the proxy group and, where possible, consider using projected market data in the models to estimate the return for the forward-looking period.

Q52. Are you aware of any regulatory commissions who have recognized that the current anomalous conditions in capital markets are causing ROE recommendations based on DCF models to be unreasonable?

A52. Yes, several regulatory commissions have addressed the effect of capital market conditions on the DCF model, including the Federal Energy Regulatory Commission ("FERC"), the Illinois Commerce Commission ("ICC"), the Pennsylvania Public Utility Commission ("PPUC"), and the Missouri Public Service Commission ("Missouri PSC").[40]

Q53. Please summarize how the FERC has responded to the effect of market conditions on the DCF.

A53. Understanding the important role that dividend yields play in the DCF model, the FERC determined that anomalous capital market conditions have caused the DCF model to understate equity costs for regulated utilities. In Opinion No. 531, the FERC noted:

> There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real world transactions fails to predict or represent the real phenomenon that is being modeled.[41]

[40] The Massachusetts DPU also acknowledged anomalous capital market conditions in D.P.U. 17-05, where they determined that it was appropriate to rely on projected interest rates. This case is discussed in more detail in Section VI.E of my testimony.

[41] FERC Docket No. EL11-66-001, Opinion No. 531, fn 286.

In Opinion No. 531, the FERC noted that the low interest rates and bond yields that persisted throughout the analytical period that was relied on (study period) resulted in anomalous market conditions and recognized the need to move away from the midpoint of the DCF analysis. In that case, the FERC relied on the CAPM and other risk premium methodologies to inform its judgment to set the return above the midpoint of the DCF results.

In Opinion No. 551, issued in September 2016, the FERC recognized that those same anomalous market conditions continued into the study period, and again concluded that it was necessary to rely on ROE estimation methodologies other than the DCF model to set the appropriate ROE:

> Though the Commission noted certain economic conditions in Opinion No. 531, the principle argument was based on low interest rates and bond yields, conditions that persisted throughout the study period. Consequently, we find that capital market conditions are still anomalous as described above…[42]

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> Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with *Hope* and *Bluefield*.[43]

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> As the Commission found in Opinion No. 531, under these circumstances, we have less confidence that the midpoint of the zone of reasonableness in this proceeding accurately reflects the

[42] FERC Docket No. EL14-12-002, Opinion No. 551, at ¶ 121.
[43] *Id*., at para. 122.

> equity returns necessary to meet the Hope and Bluefield capital attraction standards. We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies…[44]

Q54. How have the PPUC, the ICC, and the Missouri PSC addressed the effect of market conditions on the DCF?

A54. In a 2012 decision for PPL Electric Utilities, while noting that the PPUC has traditionally relied primarily on the DCF method to estimate the cost of equity for regulated utilities, the PPUC recognized that market conditions were causing the DCF model to produce results that were much lower than other models such as the CAPM and Bond Yield Plus Risk Premium. The PPUC's Order explained:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[45]

The PPUC ultimately concluded:

> As such, where evidence based on the CAPM and RP methods suggest that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[46]

In a recent ICC case, Docket No. 16-0093, Staff relied on a DCF analysis that resulted in average returns for their proxy groups of 7.24% to 7.51%. The company

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[44] *Ibid*.

[45] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

[46] *Id*., at 81.

demonstrated that these results were uncharacteristically too low by comparing the results of Staff's models to recently authorized ROEs for regulated utilities and the return on the S&P 500.[47] In Order No. 16-0093, the ICC agreed with the Company that Staff's proposed ROE of 8.04 percent was anomalous and recognized that a return that is not competitive will deter investment in Illinois.[48] In setting the return in this proceeding, the ICC recognized that it was necessary to consider other factors beyond the outputs of the financial models, particularly whether or not the return is sufficient to attract capital, maintain financial integrity, and is commensurate with returns for companies of comparable risk, while balancing the interests of customers and shareholders.[49]

Finally, in February 2018, the Missouri PSC issued a decision in Spire's 2017 gas rate case, in which the allowed ROE was set at 9.80 percent. In explaining the rationale for its decision, the Commission cited the importance of considering multiple methodologies to estimate the cost of equity and the need for the authorized ROE to be consistent with returns in other jurisdictions and to reflect the growing economy and investor expectations for higher interest rates.

> Based on the competent and substantial evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.8 percent is a fair and reasonable return on equity for Spire Missouri. That rate is

47 State of Illinois Commerce Commission, Docket No. 16-0093, Illinois-American Water Company Initial Brief, August 31, 2016, at 10.

48 Illinois Staff's analysis and recommendation in that proceeding were based on its application of the multi-stage DCF model and the CAPM to a proxy group of water utilities.

49 State of Illinois Commerce Commission Decision, Docket No. 16-0093, Illinois-American Water Company, 2016 WL 7325212 (2016), at 55.

> nearly the midpoint of all the experts' recommendations and is consistent with the national average, the growing economy, and the anticipated increasing interest rates. The Commission finds that this rate of return will allow Spire Missouri to compete in the capital market for the funds needed to maintain its financial health.[50]

Q55. What are your conclusions about the results of the DCF and CAPM models?

A55. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historical average of abnormally high stock prices results in low dividend yields that are not expected to continue over the period that the new rates will be in effect. This, in turn, underestimates the ROE for the rate period.

The use of recent historical Treasury bond yields in the CAPM also tends to underestimate the projected cost of equity. Recent experience indicates that interest rates are increasing. The expectation that bond yields will not remain at currently low levels means that the expected cost of equity would be higher than is suggested by the CAPM using historical average yields. The use of projected yields on Treasury bonds results in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be

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[50] File No. GR-2017-0215 and File No. GR-2017-0216, Missouri Public Service Commission, Report and Order, Issue Date February 21, 2018, at 34.

in effect.

B. Constant Growth DCF Model

Q56. Please describe the DCF approach.

A56. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q57. What assumptions are required for the Constant Growth DCF model?

A57. The Constant Growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q58. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A58. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended July 31, 2018.

Q59. Why did you use 30-, 90-, and 180-day averaging periods?

A59. In my Constant Growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. However, the averaging periods that I use rely on historical data which is not consistent with the forward-looking expectation that interest rates will increase. Therefore, the results of my Constant Growth DCF model may underestimate the returns of the proxy group companies. As a result, I place more weight on the mean to mean-high results produced by my Constant Growth DCF model. In addition, I calculate an additional Constant Growth DCF analysis which relies on projected market data from Value Line to more reasonably approximate future market conditions.

Q60. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A60. Yes, I did. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q61. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A61. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. Reducing the long-term growth rate to a single measure requires the assumption of a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q62. Which sources of long-term earnings growth rates did you use?

A62. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Thomson First Call (provided by Yahoo! Finance); and (3) Value Line Investment Survey.

C. Discounted Cash Flow Model Results

Q63. Please summarize the results of your Constant Growth DCF analyses.

A63. Figure 10 (*see* also Exhibit No.___(AEB-2), Schedule 2, Schedule 5, columns 12, 13 and 14 and Schedule 6, columns 12, 13 and 14) presents the range of results produced by my Initial and Refined Proxy Groups. As shown in Figure 10, for the Initial Proxy Group, the mean Constant Growth DCF results range from 9.28 percent to 9.38 percent and the mean high Constant Growth DCF results are in the range of 10.01 percent to 10.12 percent while for the Refined Proxy Group, the mean Constant Growth DCF results range from 9.35 percent to 9.46 percent and the mean high Constant Growth DCF results are in the range of 10.33 percent to 10.44 percent.

Q64. How did you calculate the range of results for the Constant Growth DCF Model?

A64. I calculated the low result for my DCF models using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all three sources.

Q65. Have you excluded any of the Constant Growth DCF results for individual companies in your proxy group?

A65. Yes, I have. It is appropriate to exclude Constant Growth DCF results below a specified threshold at which equity investors would consider such returns to provide an insufficient return increment above long-term debt costs. The average credit rating for the companies in the Initial and Refined Proxy Groups is BBB+/Baa1. The average yield on Moody's Baa-rated utility bonds for the 30 trading days ending July 31, 2018 was 4.68 percent.[51] As shown on Exhibit No.___(AEB-2), Schedule 5 and Schedule 6, I have eliminated Constant Growth DCF results lower than 7.0 percent because such returns would provide equity investors a risk premium only 232 basis points above Baa-rated utility bonds.

Q66. Have you considered the results of any other DCF analyses?

A66. Yes, because of analysts' views that utility stocks may currently be at unsustainably high prices in a rising interest rate environment, I have also considered the results of a projected Constant Growth DCF model. The projected DCF analysis relies on Value Line's projected average stock prices and dividends for the period from 2021 to 2023 and the five-year projected EPS growth rates. As shown in Exhibit No.___(AEB-2), Schedule 7 and Schedule 8, my analysis demonstrates that using the Value Line projected assumptions in the DCF model results in a 53 basis points higher (i.e., 9.86 percent vs. 9.33 percent average DCF mean result for all three dividend measurement periods shown in Exhibit No.___(AEB-2), Schedule 5) return on equity for the Initial Proxy Group and a 46 basis points higher (i.e., 9.88

[51] Source: Bloomberg Professional.

percent vs. 9.42 percent average DCF mean result for all three dividend measurement periods shown in Exhibit No.___(AEB-2), Schedule 6) return on equity for the Refined Proxy Group.

Q67. What were the results of your DCF analyses?

A67. Figure 10 summarizes the results of my DCF analyses. As shown in Figure 10, for the Initial Proxy Group, the mean DCF results range from 9.28 percent to 9.86 percent and the mean high results are in the range of 10.01 percent to 10.57 percent while for the Refined Proxy Group, the mean DCF results range from 9.35 percent to 9.88 percent and the mean high results are in the range of 10.33 percent to 10.86 percent. While I also summarize the mean low DCF results, I do not believe that the low DCF results provide a reasonable spread over the expected yields on Treasury bonds to compensate investors for the incremental risk related to an equity investment.

Figure 10: Discounted Cash Flow Results

	Mean Low	Mean	Mean High
Initial Proxy Group			
Constant Growth DCF[52]			
30-Day Average	8.53%	9.28%	10.01%
90-Day Average	8.63%	9.38%	10.12%
180-Day Average	8.60%	9.35%	10.09%
Constant Growth DCF – Projected Price and Dividends[53]			
2021-2023 Projection	9.34%	9.86%	10.57%
Refined Proxy Group			
Constant Growth DCF[54]			
30-Day Average	8.55%	9.35%	10.33%
90-Day Average	8.66%	9.46%	10.44%
180-Day Average	8.65%	9.45%	10.43%
Constant Growth DCF – Projected Price and Dividends[55]			
2021-2023 Projection	9.40%	9.88%	10.86%

Q68. What are your conclusions about the results of the DCF models?

A68. As discussed previously, one primary assumption of the DCF models is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. To the extent that utility valuations are high and may not be sustainable, it is important to consider the results of the DCF models with caution. As I indicated previously, this is due to the high utility equity valuations that occurred in the lower interest rate environment as investors have sought higher returns. With the expectation of rising interest rates, such levels are not expected to be sustained in the upcoming years. Since the low dividend yields may result in the DCF model understating investors' expected return, I have given primary weight to the mean

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52 *See* Exhibit No.___(AEB-2), Schedule 5.
53 *See* Exhibit No.___(AEB-2), Schedule 7.
54 *See* Exhibit No.___(AEB-2), Schedule 6.
55 *See* Exhibit No.___(AEB-2), Schedule 8.

and high-end DCF results. My overall recommendation also relies on the results of other ROE estimation models.

D. CAPM Analysis

Q69. Please briefly describe the Capital Asset Pricing Model.

A69. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where: K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term (r_m – r_f) represents the market risk premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (i.e., Variance (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (i.e., Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q70. What risk-free rate did you use in your CAPM analysis?

A70. I relied on two sources for my estimate of the risk-free rate: (1) the average projected 30-year U.S. Treasury bond yield for Q4 2018 through Q4 2019 of 3.56 percent;[56] and (2) the average projected 30-year U.S. Treasury bond yield for 2020 through 2024 of 4.20 percent.[57]

Q71. Why did you consider projected Treasury bond yields and not the current average yield on 30-year Treasury bonds?

A71. As discussed previously, the estimation of the cost of equity in this case should be forward looking since it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. As discussed in Section IV of my Direct Testimony, investors are expecting an increase in long-term interest rates over the next five years. This is an important consideration for equity

[56] Blue Chip Financial Forecasts, Vol. 37, No. 8, August 1, 2018, at 2.
[57] Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, at 14.

investors as they assess their return requirements. A CAPM analysis based on the current average risk-free rate fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity. For that reason, I have used the projected yields on 30-year Treasury bonds over the near-term horizon of 2018 – 2024, the period that rates will be in effect, as the risk-free rate.

Q72. Are you aware of any regulatory commissions who have recognized that current capital market conditions have affected the inputs, in particular the risk-free rate, of the CAPM Model?

A72. Yes, the Massachusetts Department of Public Utilities ("DPU") in its decision in DPU 17-05, recognized that the accommodative monetary policy pursued by the Federal Reserve to stimulate the economy following the recession in 2009 has resulted in historic lows on the yields for both short-term and long-term government bonds. As a result, the CAPM results calculated using current treasury yields maybe understating the ROE required by investors. The DPU's Order explained:

> Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near historic lows. Consequently, the Department has found that a CAPM analysis based on current treasury yields may tend to underestimate the risk-free rate over the long term and, thereby, understate the required ROE. The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that Blue Chip Financial

> Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate.[58]

Q73. What Beta coefficients did you use in your CAPM analysis?

A73. As shown on Exhibit No.___(AEB-2), Schedule 9 and Schedule 10, I used the average Beta coefficients for the companies in the Initial and Refined Proxy Groups as reported by Value Line. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index. My average Beta coefficient was 0.708 for the Initial Proxy Group and 0.733 for the Refined Proxy Group.

Q74. How did you estimate the market risk premium in the CAPM?

A74. I estimated the market risk premium based on the expected return on S&P 500 Index less the yield on the 30-year Treasury bond. I calculate the expected return on the S&P 500 Index companies for which dividend yields and long-term earnings projections are available using the Constant Growth DCF model discussed earlier in my Direct Testimony. Based on an estimated market capitalization-weighted dividend yield of 1.91 percent and a weighted long-term growth rate of 13.06 percent, the estimated required market return for the S&P 500 Index is 15.10 percent. As shown in Exhibit No.___(AEB-2), Schedule 11, the implied market risk premium over the projected yields on the 30-year U.S. Treasury bond, range from 10.90 percent to 11.54% percent.

[58] D.P.U. 17-05 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, November 30, 2017, at 693.

Q75. Have other regulators endorsed a method that is similar to the method you have used to calculate the forward-looking market risk premium?

A75. Yes. In Opinion No. 531-B, the FERC specifically endorsed a method that is similar to the method I have used to calculate the forward-looking market risk premium (i.e., applying a Constant Growth DCF analysis to the S&P 500 and using the 30-year Treasury bond yields).[59]

In response to arguments against this methodology, the FERC stated:

> We are also unpersuaded that the growth rate projection in the NETOs' CAPM study was skewed by the NETOs' reliance on analysts' projections of non-utility companies' medium-term earnings growth, or that the study failed to consider that those analysts' estimates reflect unsustainable short-term stock repurchase programs and are not long-term projections. As explained above, the NETOs based their growth rate input on data from IBES, which the Commission has found to be a reliable source of such data. Thus, the time periods used for the growth rate projections in the NETOs' CAPM study are the time periods over which IBES forecasts earnings growth. Petitioners' arguments against the time period on which the NETOs' CAPM analysis is based are, in effect, arguments that IBES data are insufficient in a CAPM study. [60]

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> While an individual company cannot be expected to sustain high short term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[61]

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59 150 FERC ¶ 61,165, Docket Nos. EL11-66-002, Opinion No. 531-B, at para. 109-111.

60 *Id.*, at para. 112.

61 *Id.*, at para. 113.

Q76. How do your estimates of the market return compare with other estimates of the overall market return?

A76. Figure 11 below summarizes estimations of the S&P 500 return calculated using earnings growth projections from Bloomberg Professional, Yahoo! Finance, and Standards and Poor's. The calculated returns for the S&P 500 range from 12.89 percent (Yahoo! Finance) to 16.64 percent (Bloomberg Professional). Therefore, the total return for the S&P 500 Index of 15.10 percent that I used to determine the forward-looking market risk premium in my CAPM analysis is within the range of returns shown in Figure 11.

Figure 11: S&P 500 Return Estimates[62]

Source	Estimate Date	Dividend Yield	Growth Estimate	S&P 500 Return
Bloomberg Professional	August 28, 2018	1.80%	14.71%	16.64%
Yahoo! Finance	August 28, 2018	1.80%	11.00%	12.89%
Standard and Poor's	August 23, 2018	1.80%	13.90%	15.82%

Q77. What are the results of your CAPM analyses?

A77. As shown in Figure 12 (*see* also Exhibit No.___(AEB-2), Schedule 11), the CAPM model results for the Initial and Refined Proxy Groups produce a range of returns from 11.73 percent to 12.19 percent.

62 Bloomberg and Yahoo! Finance do not report a dividend yield for the S&P 500; therefore, the most recent 12-month average dividend yield as of July 2018 reported in the August 23, 2018 S&P 500 Earnings and Estimate Report was used to calculate the total return.

Figure 12: CAPM Results

	Initial Proxy Group	**Refined Proxy Group**
Q4 2018-Q4 2019 Projected Risk-Free Rate (3.56%)	11.73%	12.02%
2020-2024 Projected Risk-Free Rate (4.20%)	11.91%	12.19%
Mean Result	**11.82%**	**12.11%**

E. Bond Yield Plus Risk Premium Analysis

Q78. Please describe the Bond Yield Plus Risk Premium approach.

A78. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q79. Are there other considerations that should be addressed in conducting this analysis?

A79. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[63]

Q80. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A80. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Since my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for electric utilities relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

Q81. What did your Bond Yield Plus Risk Premium analysis reveal?

A81. As shown on Figure 13 below, from 1992 through July 2018, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [5]$$

Where: RP = Risk Premium (difference between allowed ROEs and the

[63] *See e.g.,* S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

yield on 30-year U.S. Treasury bonds)

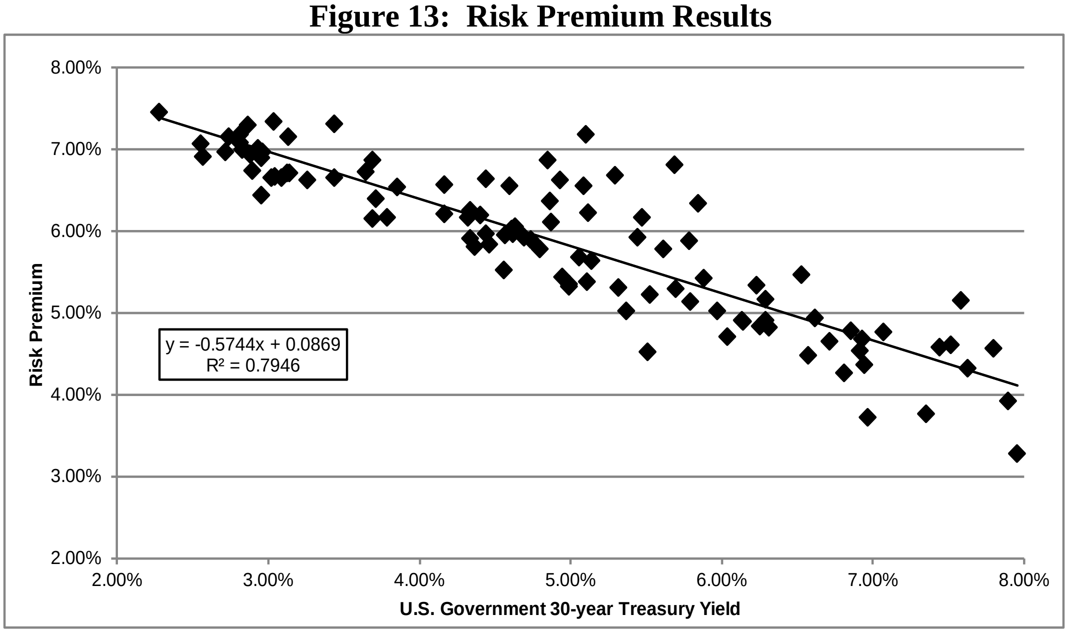
a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 592 integrated electric utility rate cases from 1992 through July 2018 as reported by Regulatory Research Associates.[64] This equation's coefficients were statistically significant at the 99.0 percent level.

Figure 13: Risk Premium Results



As shown on Exhibit No.___(AEB-2), Schedule 12, based on the near-term (2018-2019) projections of the 30-year U.S. Treasury bond yield (i.e., 3.56 percent), the

[64] This analysis began with a total of 1,101 cases and was screened to eliminate limited issue rider cases, transmission-only cases, distribution-only cases and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for 592 cases.

risk premium would be 6.65 percent, resulting in an estimated ROE of 10.21 percent. Based on longer-term (2020-2024) projections of the 30-year U.S. Treasury bond yield (i.e., 4.20 percent), the risk premium would be 6.28 percent, resulting in an estimated ROE of 10.48 percent.

Q82. How did the results of the Bond Yield Risk Premium inform your recommended ROE for Montana-Dakota?

A82. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for Montana-Dakota. The results of both my CAPM and Bond Yield Risk Premium analysis provide support for my view that the DCF model is understating investors' return requirements under current market conditions. Also, as noted above, investors will consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of electric utilities across the US.

VII. REGULATORY AND BUSINESS RISKS

Q83. Is it reasonable to rely exclusively on the mean DCF, CAPM and Risk Premium results for the proxy group to provide an appropriate estimate of the cost of equity for Montana-Dakota?

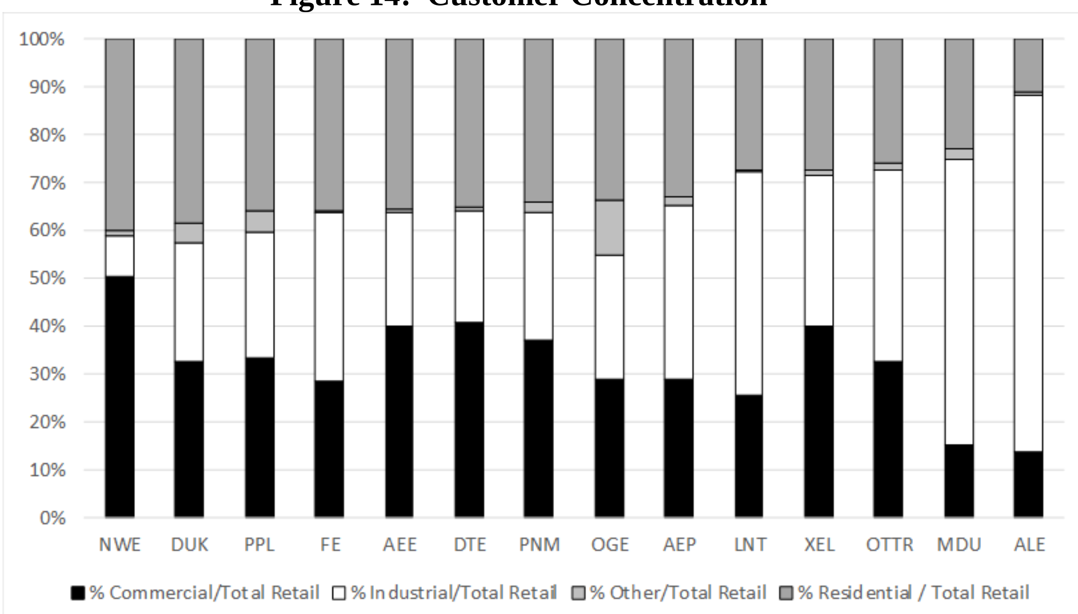
A83. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. It is also important to consider the specific risk factors of the company, as compared with the proxy group to determine where the Company's cost of equity falls within the range of results.

A. Customer Concentration

Q84. Please summarize Montana-Dakota's customer concentration risk.

A84. Approximately 60 percent of Montana-Dakota's 2017 total retail electric sales in Montana were derived from industrial customers. As shown in Figure 14, Montana-Dakota's commercial and industrial sales volume as a percentage of total retail electric sales was 75 percent, which is higher than all but one of the companies in the Initial and Refined Proxy Groups.[65]

Figure 14: Customer Concentration[66]



[65] Does not include "other" or residential customers.

[66] Source: SNL Financial - Other sales includes: Total Public Street and Highway Lighting, Other Sales to Public Authorities, Sales to Railroad and Railways, and Interdepartmental Sales.

Q85. How does customer concentration affect business risk?

A85. A relatively high concentration of commercial and industrial customers results in higher business risk. Since the customers are large, they can represent a significant portion of a company's sales which could be lost if a customer goes out of business or switches suppliers. As noted by Dhaliwal, Judd, Serfling and Shaikh in their article, *Customer Concentration Risk and the Cost of Equity Capital*:

> Depending on a major customer for a large portion of sales can be risky for a supplier for two primary reasons. First, a supplier faces the risk of losing substantial future sales if a major customer becomes financially distressed or declares bankruptcy, switches to a different supplier, or decides to develop products internally. Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock returns to the announcement that a major customer declares bankruptcy. Further, a customer's weak financial condition or actions could signal inherent problems about the supplier's viability to its remaining customers and lead to compounding losses in sales. Second, a supplier faces the risk of losing anticipated cash flows from being unable to collect outstanding receivables if the customer goes bankrupt. This assertion is consistent with the finding that suppliers offering customers more trade credit experience larger negative abnormal stock returns around the announcement of a customer filing for Chapter 11 bankruptcy (Jorion and Zhang, 2009; Kolay et al., 2015).[67]

Therefore, a company that has a high degree of customer concentration will be inherently riskier than a company that derived income from a larger customer base. Furthermore, as Dhaliwal, Judd, Serfling and Shaik detail in the article, the

[67] Dhaliwal, Dan S., J. Scott Judd, Matthew A. Serfling, and Sarah Shaikh. "Customer Concentration Risk and the Cost of Equity Capital." SSRN Electronic Journal (2016): 1-2. Web.

increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity.[68]

Q86. Please describe how changes in economic conditions and Montana-Dakota's high degree of customer concentration can affect its business risk?

A86. Montana-Dakota is unique in that unlike most electric and natural gas utilities, the Company is dependent on a single customer for a large portion of its electric sales in Montana. The customer is engaged in oil and natural gas exploration and production. It is well-documented that the oil and natural gas production industry is very cyclical. Additionally, like other industries, the oil and natural gas production industry is also dependent on the general business cycle. As a result, the customer's production could change based on general or industry specific economic conditions thereby impacting the customer's energy consumption.

Furthermore, Montana-Dakota is also in direct competition with other sources of energy such as natural gas, diesel, solar and wind among others. This creates an additional risk that customers in the commercial and industrial classes could install onsite generation to serve a substantial portion of their energy needs. For Montana-Dakota, the risk is much greater since the Company depends on a single customer for a substantial portion of sales.

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68 *Id.*, at 4.

Q87. How dependent is Montana-Dakota's electric volume on the customer engaged in oil and natural gas production?

A87. The customer represents 28 percent of the Company's retail electric sales in Montana.[69] Therefore, if the customer were to decrease production as a result of fluctuations in the price of oil and natural gas or install onsite generation to serve its energy needs, Montana-Dakota could experience a significant decrease in electric sales. Furthermore, if the customer were to reduce output due to decreases in oil prices, the effect on the Montana-Dakota system could be compounded if reduced production affected the local economy. Thus, Montana-Dakota's reliance on a single large customer's load results in increased risk with respect to sales, earnings, and cash flow.

Q88. What is your conclusion regarding the Company's customer concentration and its effect on the cost of equity for Montana-Dakota's electric operations in Montana?

A88. Montana-Dakota is heavily reliant on sales to commercial and industrial customers. As noted above, 75 percent of Montana-Dakota's total retail electric sales in Montana were to commercial and industrial customers. This concentration is higher than all but one of the proxy group companies. In addition, 28 percent of Montana-Dakota's electric retail sales are to one customer. A high degree of customer concentration increases Montana-Dakota's risk related to competition from alternative energy sources and economic conditions. Increased customer diversity decreases the effect that any one customer can have on a company's sales.

[69] Data provided by Montana-Dakota Utilities Co.

Thus, Montana-Dakota's heavy customer concentration implies that the Company has an above average risk profile when compared to the companies in the proxy group.

B. Small Size Risk

Q89. Please explain the risk associated with small size.

A89. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect". While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[70]

Q90. How does the smaller size of a utility affect its business risk?

A90. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater

[70] Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q91. How does Montana-Dakota's electric operations in Montana compare in size to the companies in the Initial Proxy Group?

A91. Montana-Dakota's electric operations in Montana are substantially smaller than the median for the companies in my Initial Proxy Group in terms of market capitalization. Exhibit No.___(AEB-2), Schedule 13 provides the actual market capitalization for the companies in my Initial Proxy Group and estimates the implied market capitalization for Montana-Dakota (i.e., the implied market capitalization if Montana-Dakota's electric operations in Montana were a stand-alone publicly-traded entity). To estimate the size of the Company's market capitalization relative to the Initial Proxy Group, I calculated Montana-Dakota's proposed capital structure equity component of $106.8 million by multiplying Montana-Dakota's test year rate base of $211.70 million by Montana-Dakota's test year common equity ratio of 50.45 percent. I then applied the median market-to-book ratio for the proxy group of 1.89 to Montana-Dakota's implied common equity balance and arrived at an implied market capitalization of approximately $201.8 million, or 2.05 percent of the median market capitalization for the Initial Proxy Group.

Q92. How did you estimate the size premium for Montana-Dakota?

A92. Given this relative size information, it is possible to estimate the impact of size on the ROE for Montana-Dakota using Duff and Phelps data that estimates the stock risk premia based on the size of a company's market capitalization. As shown in Exhibit No.___(AEB-2), Schedule 13, the median market capitalization of the Initial Proxy Group of approximately $9.83 billion corresponds to the third decile of the Duff and Phelps market capitalization data. Based on Duff and Phelps' analysis, that decile corresponds to a size premium of 0.89 percent (i.e., 89 basis points). Montana-Dakota's implied market capitalization of approximately $201.8 million falls within the tenth decile, which comprises market capitalization levels up to $262.9 million and corresponds to a size premium of 5.59 percent (i.e., 559 basis points). The difference between those size premia is 470 basis points (i.e., 5.59 percent minus 0.89 percent).

Q93. Have regulators in other jurisdictions considered a company's small size in the determination of the authorized ROE?

A93. Yes. In Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[71] Thus, the RCA awarded AEL&P an ROE of 12.875 percent which was 108 basis points above the highest return on equity estimate from any model presented in the case.[72] Similarly, in Order No. 19, the RCA noted that small size

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71 Docket No. U-10-29, In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by Alaska Electric Light and Power Company, Order entered September 2, 2011 (Order No. 15) at 37.

72 Id, at 32 and 37.

as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions increased the risk of ENSTAR Natural Gas Company.[73] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[74]

This is important, because as will be discussed in more detail below, Montana-Dakota's electric operations in Montana face similar business risks as ENSTAR Natural Gas Company in addition to small size such as regulatory lag, weather risk, and alternative rate mechanisms.

Q94. How have you considered the smaller size of Montana-Dakota in your recommendation?

A94. While I have estimated the effect of Montana-Dakota's small size on the ROE, I am not proposing a specific adjustment for this risk factor. Rather, I believe it is important to consider the small size of Montana-Dakota's electric operations in Montana in the determination of where, within the range of analytical results, the Company's required ROE falls. Therefore, the additional risk associated with small

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[73] Docket No. U-16-066, In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR Natural Gas Company, A Division of Semco Energy, Inc., Order entered September 22, 2017 (Order No. 19) at 50-52.

[74] *Ibid.*

size indicates that the Company's ROE should be established above the mean results for the companies in my Initial Proxy Group.

C. Flotation Cost

Q95. What are flotation costs?

A95. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q96. Why is it important to consider flotation costs in the allowed ROE?

A96. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q97. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A97. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year, but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, whether an issuance occurs during the test year, or is planned for the test year, is irrelevant, because failure to allow recovery of past flotation costs may deny Montana-Dakota the opportunity to earn its required ROR in the future.

Q98. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A98. Suppose MDU Resources issues stock with a value of $100, and an equity investor invests $100 in MDU Resources in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU Resources ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU Resources invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q99. Is the date of MDU Resources last issued common equity important in the determination of flotation costs?

A99. No. As shown in Exhibit No.___(AEB-2), Schedules 14 and 15, MDU Resources closed on equity issuances of approximately $58 million and $54 million (for a total of 4.7 million shares of common stock) in November 2002 and February 2004, respectively. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that he should have a reasonable opportunity to earn a return on the full amount of capital that he has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which he has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q100. Is the need to consider flotation costs recognized by the academic and financial communities?

A100. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair ROR. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation

> costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[75]

Q101. How did you calculate the flotation costs for Montana-Dakota?

A101. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU Resources in its two most recent common equity issuances. Those issuance costs were applied to my Initial and Refined Proxy Groups. Based on the issuance costs provided in Exhibit No.___(AEB-2), Schedules 14 and 15, flotation costs for Montana-Dakota are approximately 0.14 percent (i.e., 14 basis points) for both the Initial and Refined Proxy Groups.

Q102. Do your final results include an adjustment for flotation cost recovery?

A102. No. I did not make an explicit adjustment for flotation costs to any of my quantitative analyses. Rather, I provide the above result for consideration in my recommended ROE, which reflects the range of results from my Constant Growth DCF, Projected DCF, CAPM, and Risk Premium analyses.

D. Montana-Dakota's Capital Expenditure Plan

Q103. Please summarize the Company's capital expenditure requirements.

A103. The Company's current projections for 2019 through 2022 include approximately $97.5 million in capital investments for the period.[76] Based on the Company's net utility plant of approximately $231.51 million as of December 31, 2017,[77] the $97.5

75 Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.
76 Data provided by Montana-Dakota Utilities Co. for Capital Expenditures 2019-2022.
77 Data provided by Montana-Dakota Utilities Co.

million anticipated capital expenditures is approximately 42.10 percent of Montana-Dakota's net utility plant as of December 31, 2017.

Q104. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A104. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q105. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A105. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more

> favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[78]

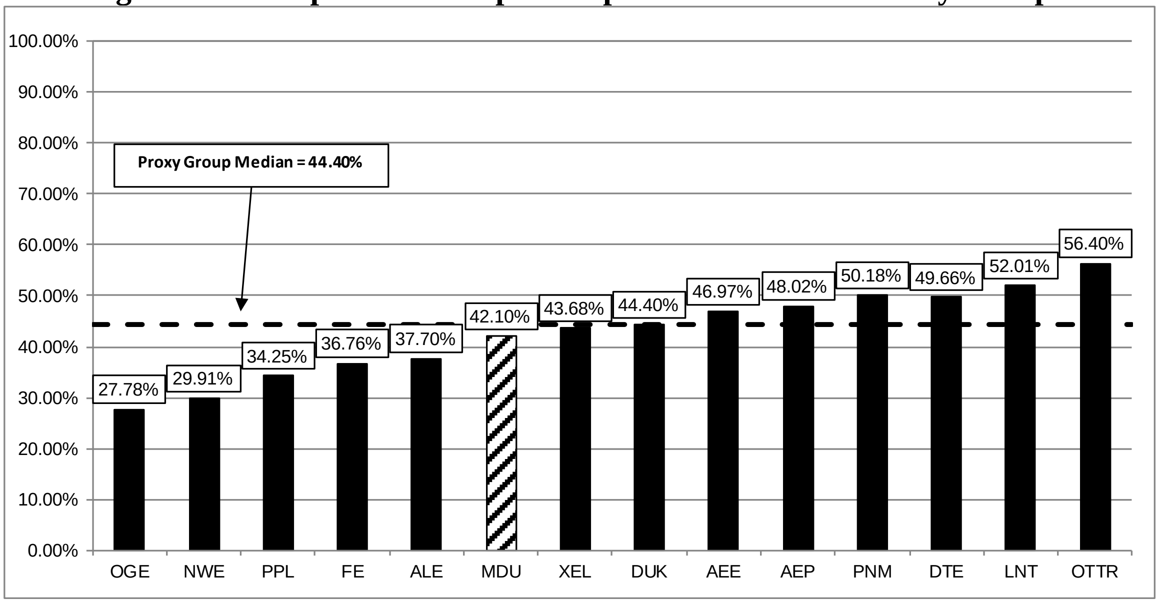
Therefore, to the extent that Montana-Dakota's rates do not permit the opportunity to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q106. How do Montana-Dakota's capital expenditure requirements compare to those of the companies in the Initial Proxy Group?

A106. As shown at Exhibit No.___(AEB-2), Schedule 16, I calculated the ratio of expected capital expenditures to net utility plant for Montana-Dakota and each of the companies in the Initial Proxy Group by dividing each company's projected capital expenditures for the period from 2019-2022 by that company's total net utility plant as of December 31, 2017. As shown in Exhibit No.___(AEB-2), Schedule 16 (*see* also Figure 15 below), Montana-Dakota's ratio of capital expenditures as a percentage of net utility plant of 42.10 percent is approximately 0.95 times the median for the proxy group companies of 44.40 percent. This result indicates moderate risk relative to the Initial Proxy Group.

78 S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Figure 15: Comparison of Capital Expenditures – Initial Proxy Group



Q107. Does Montana-Dakota have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A107. No. Montana-Dakota currently has not received approval to recover capital investment costs between rate cases utilizing a capital tracking mechanism. Therefore, Montana-Dakota depends entirely on rate case filings for capital cost recovery. However, significant programs like Montana-Dakota's that drive capital expenditure requirements generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No.___(AEB-2), Schedule 17, 54 percent of the companies in the Initial Proxy Group have some form of capital cost recovery mechanisms in place. Since Montana-Dakota does not currently have a capital tracking mechanism, Montana-Dakota's risk relative to the proxy group is significantly increased.

Q108. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A108. The Company's capital expenditure requirements as a percentage of net utility plant are escalating over the next few years. Additionally, unlike a number of the operating subsidiaries of the Initial Proxy Group, Montana-Dakota does not have a comprehensive capital tracking mechanism to recover the Company's projected capital expenditures. Therefore, Montana-Dakota's significant capital expenditures plan and limited ability to recover the capital investment costs in a timely manner results in a risk profile that is greater than that of the Initial Proxy Group and supports an ROE toward the higher end of the reasonable range of ROEs.

E. Regulatory Risk

Q109. Please explain how the regulatory environment affects investors' risk assessments.

A109. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. Montana-Dakota is no exception. It must finance its operations and requires the opportunity to earn a reasonable return on its invested capital in order to maintain its financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q110. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A110. Yes, both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns;

(3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.0 percent. Therefore, Moody's assigns regulatory risk a 50.0 percent weighting in the overall assessment of business and financial risk for regulated utilities.[79]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[80] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation."[81]

Q111. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A111. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility

[79] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 6.
[80] Standard & Poor's, Assessing U.S. Utility Regulatory Environments, August 10, 2016, at 2.
[81] *Ibid*.

adapts to that environment are the most important credit considerations."[82] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[83]

Q112. Have you conducted any analysis of the regulatory framework in Montana relative to the jurisdictions in which the companies in your Initial Proxy Group operate?

A112. Yes. I have evaluated the regulatory framework in Montana on four factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These are: 1) test year convention (i.e., forecast vs. historical); 2) method for determining rate base (i.e., average vs. year-end); 3) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and 4) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit No.___(AEB-2), Schedule 17, and are summarized below.

<u>Test year convention</u>: Montana-Dakota is required to use a historical test year adjusted for certain known and measurable changes in Montana, while 52 percent of the electric operating companies held by the Initial Proxy

82 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 9.
83 *Ibid*.

Group provide service in jurisdictions that use a fully or partially forecast test year.

Rate base: Montana-Dakota's rate base in Montana is determined based on the average original cost, while 57 percent of the electric operating companies held by the Initial Proxy Group are allowed to use year-end rate base, meaning that the rate base includes capital additions that occurred in the second half of the test year and is more reflective of net utility plant going forward.

Volumetric risk: Montana-Dakota does not have protection against volumetric risk in Montana, either through a revenue decoupling mechanism or a weather normalization adjustment clause. By comparison, 35 percent of the electric operating companies held by the Initial Proxy Group have some form of protection against volumetric risk.

Capital cost recovery: As discussed above, Montana-Dakota does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, 54 percent of the electric operating companies held by the Initial Proxy Group have some form of capital cost recovery mechanism in place.

Q113. Have you developed any additional analyses to evaluate the regulatory environment in Montana as compared to the jurisdictions in which the companies in your Initial Proxy Group operate?

A113. Yes. I have conducted two additional analyses to compare the regulatory framework of Montana to the jurisdictions in which the companies in the Initial Proxy Group operate. Specifically, I considered two different rankings: (1) the Regulatory Research Associates ("RRA") ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q114. Please explain how you used the RRA ratings to compare the regulatory jurisdictions of the proxy group companies with the Company's regulatory jurisdiction.

A114. RRA develops their ranking based on their assessment of how investors perceive the regulatory risk associated with ownership of utility securities in that jurisdiction, specifically reflecting their assessment of the probable level and quality of earnings to be realized by the State's utilities as a result of regulatory, legislative, and court actions. RRA assigns a ranking for each regulatory jurisdiction between "Above Average/1" to "Below Average/3," with nine total rankings between these categories. I applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking ("9") and "Below Average/3" assigned the lowest ranking ("1"). As shown in Exhibit No.___(AEB-2), Schedule 18, the relative perception of regulatory risk for Montana-Dakota is much higher than the jurisdictions for the companies in the Initial Proxy Group. The Montana regulatory environment is ranked as "Below Average/1," while the proxy group is ranked between "Average/2" and "Average/1." Additionally, Montana is one of the nine Commissions[84] out of the 53 Commissions that RRA ranks to receive a rating of either "Below Average/1", "Below Average/2" or "Below Average/3".

Q115. How did you conduct your analysis of the S&P Credit Supportiveness?

A115. S&P classifies the regulatory jurisdictions into five categories ranging from "Credit Supportive" to "Most Credit Supportive" based on the level of credit supportiveness. Similar to the RRA regulatory ranking analysis discussed above, I assigned a numerical ranking to each jurisdiction ranked by S&P, from most credit supportive ("5") to credit supportive ("1"). As shown in Exhibit No.___(AEB-2), Schedule 19, the Initial Proxy Group is ranked between very credit supportive and highly credit supportive while the Montana regulatory jurisdiction is only ranked as more credit supportive. Thus, similar to the results using the RRA regulatory rankings, Montana is again below the average for the Initial Proxy Group.

Q116. Has RRA provided recent commentary regarding its regulatory ranking for the Montana?

A116. Yes. In February 2018, RRA updated its evaluation of the regulatory environment in Montana and noted the following:

> The regulatory climate in Montana is somewhat restrictive from an investor point-of-view. Authorized ROEs have generally been consistent with prevailing industry averages at the time established,

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84 The other eight Commissions are the Connecticut Public Utilities Regulatory Authority, the District of Columbia Public Service Commission, the Kansas Corporation Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities, the New Mexico Public Regulation Commission, the Public Service Commission of West Virginia and the Regulatory Commission of Alaska.

> as calculated by Regulatory Research Associates, an offering of S&P Global Market Intelligence. In addition, the PSC relies upon historical test periods, which coupled with an average rate base valuation methodology, exacerbates regulatory lag. While many rate cases are resolved by settlements, the regulators have been known to modify certain aspects of the agreement, and in so doing, lowering the authorized rate increase. State law initially called for implementation of retail competition for electric generation, but subsequent legislation reversed this process. While Montana utilities are permitted to seek pre-approval of the regulatory framework to apply to new generation assets, a cash return on construction work in progress is not allowed. Also, the PSC has opposed strategic mergers, rejecting one recent major deal outright. Regulation of the gas local distribution companies, or LDCs, has been more stable, as retail choice has been in place since the late-1990s, and LDCs are now permitted to acquire upstream assets. Both the electric and gas utilities have mechanisms in place to provide expedited recognition of changes in commodity and related costs; some of these include cost-sharing provisions. A proceeding is pending regarding a utility's proposal to implement an electric cost supply mechanism that would also include a cost-sharing provisions. However, there are no other innovative or alternative ratemaking provisions in place. In conjunction with the Nov. 15, 2017, issuance of its rankings, RRA lowered the ranking of the Montana regulatory climate to Below Average/1 from Average/3, primarily due to a rebalancing of the rankings; Montana had been at the lower end of the Average/3 category.[85]

Q117. What are your conclusions regarding the perceived risks related to the Montana regulatory environment?

A117. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the Initial Proxy Group have more timely cost recovery (through forecasted test years,

[85] Regulatory Research Associates, Profile of Montana Public Service Commission, accessed August 30, 2018.

cost recovery trackers and revenue stabilization mechanisms) than Montana-Dakota has in Montana. In addition, the RRA jurisdictional ranking and the S&P credit supportiveness ranking for Montana indicates greater risk than the average for the Initial Proxy Group. Therefore, the average ROE for the Initial Proxy Group would understate the return on equity that an investor would require in Montana because the risks of timely and full cost recovery are greater for Montana-Dakota in Montana than for the proxy group. For that reason, I conclude that the authorized ROE for Montana-Dakota should be higher than the Initial Proxy Group mean.

VIII. CAPITAL STRUCTURE

Q118. What is Montana Dakota's proposed capital structure?

A118. The Company's proposal is to establish a capital structure consisting of 50.45 percent common equity, 42.19 percent long-term debt, and 7.36 percent short-term debt.

Q119. How does the business risk of vertically-integrated electric utilities compare to the business risk of other regulated utilities?

A119. According to Moody's, generation ownership causes vertically-integrated electric utilities to have higher business risk than either electric transmission and distribution companies, or natural gas distribution or transportation companies.[86] As a result of this higher business risk, integrated electric utilities typically require a higher percentage of equity in the capital structure than other electric or gas utilities.

[86] Moody's, Rating Methodology: Electric and Gas Utilities, December 23, 2013, at 23-24.

Q120. Did you conduct any analysis to determine if Montana-Dakota's requested equity ratio was reasonable?

A120. Yes, I did. I reviewed the capital structures of the companies in my Initial and Refined Proxy Groups at the operating subsidiary level. Since the return on equity is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure of the proxy groups to benchmark the equity ratio for the Company.

Q121. Please discuss your analysis of the capital structures of the companies in the Initial and Refined Proxy Groups.

A121. I calculated the mean proportions of common equity, long-term debt, short-term debt and preferred equity over the most recent eight quarters [87] for each of companies in my Initial and Refined Proxy Groups at the operating subsidiary level. My analysis of the capital structures of the companies in the Initial and Refined Proxy Groups is provided in Exhibit No.___(AEB-2), Schedule 20 and Schedule 21, respectively. As shown in those Schedules, the mean equity ratio for the Initial Proxy Group at the operating utility company level is 51.70 percent while the mean equity ratio for the Refined Proxy Group at the operating utility company level is 52.47 percent. The average equity ratios for the utility operating companies held by the Initial Proxy Group range from a low of 45.32 percent to a high of 58.56 percent while the equity ratios for the Refined Proxy Group range from 47.49

[87] The source data for this analysis is the operating company data provided in FERC Form 1 reports. Due to the timing of those filings, my average capital structure analysis uses the quarterly capital structures reported for the proxy group companies for the period from the second quarter of 2016 through the first quarter of 2018.

percent to 58.56 percent. Montana-Dakota's equity ratio of 50.45 percent is well within the range established by the capital structures of the operating companies in the Initial and Refined Proxy Groups.

Q122. Is there a relationship between the equity ratio and the authorized ROE?

A122. Yes. There is a direct relationship between the equity ratio and the authorized ROE. In particular, the equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. To the extent the equity ratio is reduced, a corresponding increase is necessary in the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q123. What is your conclusion with regard to Montana-Dakota's proposed capital structure?

A123. The proposed equity ratio for Montana-Dakota in Montana is slightly less than the mean equity ratios of the electric operating utilities held within the Initial and Refined Proxy Groups. As such, my conclusion is that Montana-Dakota's proposed capital structure is reasonable.

IX. CONCLUSIONS AND RECOMMENDATION

Q124. What is your conclusion regarding a fair ROE for Montana-Dakota?

A124. Based on the quantitative and qualitative analyses presented in my Direct Testimony, and in light of the business and financial risks of Montana-Dakota as compared to the Initial and Refined Proxy Groups and the effects of Federal tax reform on the cash flow metrics of utilities, it is my view that an ROE of 10.30 percent would fairly balance the interests of customers and shareholders. This ROE would enable the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable and affordable electric utility service to customers in Montana.

Figure 16: Summary of Analytical Results[88]

Initial Proxy Group			
Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.53%	9.28%	10.01%
90-Day Average	8.63%	9.38%	10.12%
180-Day Average	8.60%	9.35%	10.09%
Constant Growth Average	8.59%	9.33%	10.07%
Projected DCF			
	Mean Low	Mean	Mean High
2021-2023 Projection	9.34%	9.86%	10.57%
CAPM			
	Q4 2018 – Q4 2019 Projected Risk-Free Rate (3.56%)		2020-2024 Projected Risk-Free Rate (4.20%)
CAPM	11.73%		11.91%
CAPM Mean Result	11.82%		
Refined Proxy Group			
Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.55%	9.35%	10.33%
90-Day Average	8.66%	9.46%	10.44%
180-Day Average	8.65%	9.45%	10.43%
Constant Growth Average	8.62%	9.42%	10.40%
Projected Growth DCF			
	Mean Low	Mean	Mean High
2021-2023 Projection	9.40%	9.88%	10.86%
CAPM			
	Q4 2018 – Q4 2019 Projected Risk-Free Rate (3.56%)		2020-2024 Projected Risk-Free Rate (4.20%)
CAPM	12.02%		12.19%
CAPM Mean Result	12.11%		
Bond Yield Plus Risk Premium			
	Q4 2018 – Q4 2019 Projected Risk-Free Rate (3.56%)		2020-2024 Projected Risk-Free Rate (4.20%)
Risk Premium Analysis	10.21%		10.48%
Risk Premium Mean Result	10.34%		

88 The analytical results included in Figure 16 reflect the results of the Constant Growth and Projected DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

Q125. What is your conclusion with respect to Montana-Dakota's proposed capital structure?

A125. My conclusion is that Montana-Dakota's proposed common equity ratio of 50.45 percent is reasonable when compared to the capital structures of the companies in the Initial and Primary Proxy Groups.

Q126. Does this conclude your Direct Testimony?

A126. Yes, it does.

Ann E. Bulkley
Senior Vice President

Ms. Bulkley more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has advised clients seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings in which she did not testify.

Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice. In addition, Ms. Bulkley has relied on other simulation based valuation methodologies.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.

- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared,

supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed, and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Senior Vice President
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

M.A., Economics, Boston University, 1995

B.A., Economics and Finance, Simmons College, 1991

Certified General Appraiser licensed in the Commonwealth of Massachusetts and the States of Michigan and New Hampshire

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Commonwealth of Massachusetts Appellate Tax Board				
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Connecticut Public Utilities Regulatory Authority				
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
Federal Energy Regulatory Commission				
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Indiana Utility Regulatory Commission				
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity

SPONSOR	**DATE**	**CASE/APPLICANT**	**DOCKET /CASE NO.**	**SUBJECT**
Massachusetts Appellate Tax Board				
FirstLight Hydro	06/17	FirstLight Hydro		Valuation of generating asset
Massachusetts Department of Public Utilities				
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Covert Township	05/18	New Covert Generating Co., LLC.		Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-2085 Case No. SR-17-2086	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Hampshire- Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of utility property
New Jersey Board of Public Utilities				
Public Service Electric & Gas Company	01/18	Public Service Electric & Gas Company	BPU Docket No. GR17070776	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-001398-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company	05/15	New York State Electric and Gas Company	Case No. 15-G-0284	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0059	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. C-17-E-0238	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Gas 17-G-0460 Electric 17-E-0459	Return on Equity
North Dakota Public Service Commission				
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Public Utility Commission of Pennsylvania				
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Public Service Commission of West Virginia				
West Virginia American Water Company	04/18	West Virginia American Water Company		Return on Equity

SUMMARY OF ROE ANALYSES RESULTS[1]

Initial Proxy Group			
Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.53%	9.28%	10.01%
90-Day Average	8.63%	9.38%	10.12%
180-Day Average	8.60%	9.35%	10.09%
Constant Growth Average	8.59%	9.33%	10.07%
Projected DCF			
	Mean Low	Mean	Mean High
2021-2023 Projection	9.34%	9.86%	10.57%
CAPM			
	Near-Term Blue Chip Forecast Yield		Long-Term Blue Chip Forecast Yield
CAPM	11.73%		11.91%
CAPM Mean Result	11.82%		
Refined Proxy Group			
Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.55%	9.35%	10.33%
90-Day Average	8.66%	9.46%	10.44%
180-Day Average	8.65%	9.45%	10.43%
Constant Growth Average	8.62%	9.42%	10.40%
Projected Growth DCF			
	Mean Low	Mean	Mean High
2021-2023 Projection	9.40%	9.88%	10.86%
CAPM			
	Near-Term Blue Chip Forecast Yield		Long-Term Blue Chip Forecast Yield
CAPM	12.02%		12.19%
CAPM Mean Result	12.11%		
Treasury Yield Plus Risk Premium			
	Near-Term Blue Chip Forecast Yield		Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	10.21%		10.48%
Risk Premium Mean Result	10.34%		

Notes:

[1] The analytical results included in the table reflect the results of the Constant Growth and Projected DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

PROXY GROUP SCREENING DATA AND RESULTS - INITIAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Generation Assets Included in Rate Base	% Regulated Coal Generation Capacity > 30%	% Regulated Operating Income > 70%	% Regulated Electric Operating Income > 80%	Announced Merger
ALLETE, Inc.	ALE	Yes	BBB+	Yes	Yes	Yes	53.66%	83.27%	97.38%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	35.26%	100.55%	94.54%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	49.98%	100.71%	91.13%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	51.55%	91.45%	100.00%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	Yes	52.08%	99.76%	80.29%	No
Duke Energy Corporation	DUK	Yes	A-	Yes	Yes	Yes	32.50%	105.93%	94.98%	No
FirstEnergy Corporation	FE	Yes	BBB-	Yes	Yes	Yes	88.89%	103.36%	100.00%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	32.76%	97.42%	85.31%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	37.95%	101.79%	100.00%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	66.95%	77.54%	100.00%	No
PNM Resources, Inc.	PNM	Yes	BBB+	Yes	Yes	Yes	34.60%	99.92%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	Yes	62.96%	112.52%	95.53%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	34.46%	100.00%	85.43%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: SNL Financial
[6] Source: SNL Financial
[7] Source: Form 10-Ks for 2017, 2016 & 2015
[8] Source: Form 10-Ks for 2017, 2016 & 2015
[9] SNL Financial News Releases

PROXY GROUP SCREENING DATA AND RESULTS - REFINED PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company		Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Generation Assets Included in Rate Base	% Regulated Coal Generation Capacity > 35%	% Regulated Operating Income > 70%	% Regulated Electric Operating Income > 80%	Announced Merger
ALLETE, Inc.	ALE	Yes	BBB+	Yes	Yes	Yes	53.66%	83.27%	97.38%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	35.26%	100.55%	94.54%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	49.98%	100.71%	91.13%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	51.55%	91.45%	100.00%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	Yes	52.08%	99.76%	80.29%	No
FirstEnergy Corporation	FE	Yes	BBB-	Yes	Yes	Yes	88.89%	103.36%	100.00%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	37.95%	101.79%	100.00%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	66.95%	77.54%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	Yes	62.96%	112.52%	95.53%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: SNL Financial
[6] Source: SNL Financial
[7] Source: Form 10-Ks for 2017, 2016 & 2015
[8] Source: Form 10-Ks for 2017, 2016 & 2015
[9] SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF -- INITIAL PROXY GROUP

											All Proxy Group			With Exclusions	
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.24	$77.44	2.89%	2.97%	5.00%	6.00%	6.00%	5.67%	7.97%	8.64%	8.98%	7.97%	8.64%	8.98%
Alliant Energy Corporation	LNT	$1.34	$42.48	3.15%	3.25%	6.50%	5.85%	5.60%	5.98%	8.84%	9.23%	9.76%	8.84%	9.23%	9.76%
Ameren Corporation	AEE	$1.83	$60.79	3.01%	3.11%	7.50%	6.30%	6.50%	6.77%	9.41%	9.88%	10.62%	9.41%	9.88%	10.62%
American Electric Power Company, Inc.	AEP	$2.48	$69.75	3.56%	3.65%	4.50%	5.59%	5.60%	5.23%	8.14%	8.88%	9.26%	8.14%	8.88%	9.26%
DTE Energy Company	DTE	$3.53	$105.08	3.36%	3.46%	7.00%	5.67%	5.30%	5.99%	8.75%	9.45%	10.48%	8.75%	9.45%	10.48%
Duke Energy Corporation	DUK	$3.56	$79.72	4.47%	4.57%	5.50%	4.01%	4.60%	4.70%	8.56%	9.27%	10.09%	8.56%	9.27%	10.09%
FirstEnergy Corporation	FE	$1.44	$35.62	4.04%	4.13%	3.00%	Negative	6.00%	4.50%	7.10%	8.63%	10.16%	7.10%	8.63%	10.16%
NorthWestern Corporation	NWE	$2.20	$57.94	3.80%	3.85%	3.50%	2.45%	2.30%	2.75%	6.14%	6.60%	7.36%			7.36%
OGE Energy Corporation	OGE	$1.33	$35.36	3.76%	3.86%	6.00%	4.70%	4.80%	5.17%	8.55%	9.03%	9.87%	8.55%	9.03%	9.87%
Otter Tail Corporation	OTTR	$1.34	$48.24	2.78%	2.89%	7.50%	9.00%	n/a	8.25%	10.38%	11.14%	11.90%	10.38%	11.14%	11.90%
PNM Resources, Inc.	PNM	$1.06	$38.51	2.75%	2.83%	7.50%	5.15%	5.10%	5.92%	7.92%	8.75%	10.36%	7.92%	8.75%	10.36%
PPL Corporation	PPL	$1.64	$28.49	5.76%	5.85%	2.00%	2.17%	6.00%	3.39%	7.81%	9.24%	11.93%	7.81%	9.24%	11.93%
Xcel Energy Inc.	XEL	$1.52	$45.71	3.33%	3.42%	5.50%	5.96%	5.80%	5.75%	8.92%	9.17%	9.38%	8.92%	9.17%	9.38%
Mean				3.59%	3.68%	5.46%	5.24%	5.30%	5.39%	8.35%	9.07%	10.01%	8.53%	9.28%	10.01%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

90-DAY CONSTANT GROWTH DCF -- INITIAL PROXY GROUP

											All Proxy Group			With Exclusions	
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.24	$75.35	2.97%	3.06%	5.00%	6.00%	6.00%	5.67%	8.05%	8.72%	9.06%	8.05%	8.72%	9.06%
Alliant Energy Corporation	LNT	$1.34	$41.50	3.23%	3.33%	6.50%	5.85%	5.60%	5.98%	8.92%	9.31%	9.83%	8.92%	9.31%	9.83%
Ameren Corporation	AEE	$1.83	$58.27	3.14%	3.25%	7.50%	6.30%	6.50%	6.77%	9.54%	10.01%	10.76%	9.54%	10.01%	10.76%
American Electric Power Company, Inc.	AEP	$2.48	$68.07	3.64%	3.74%	4.50%	5.59%	5.60%	5.23%	8.23%	8.97%	9.35%	8.23%	8.97%	9.35%
DTE Energy Company	DTE	$3.53	$102.94	3.43%	3.53%	7.00%	5.67%	5.30%	5.99%	8.82%	9.52%	10.55%	8.82%	9.52%	10.55%
Duke Energy Corporation	DUK	$3.56	$77.72	4.58%	4.69%	5.50%	4.01%	4.60%	4.70%	8.68%	9.39%	10.21%	8.68%	9.39%	10.21%
FirstEnergy Corporation	FE	$1.44	$34.56	4.17%	4.26%	3.00%	Negative	6.00%	4.50%	7.23%	8.76%	10.29%	7.23%	8.76%	10.29%
NorthWestern Corporation	NWE	$2.20	$55.14	3.99%	4.04%	3.50%	2.45%	2.30%	2.75%	6.34%	6.79%	7.56%			7.56%
OGE Energy Corporation	OGE	$1.33	$33.97	3.92%	4.02%	6.00%	4.70%	4.80%	5.17%	8.71%	9.18%	10.03%	8.71%	9.18%	10.03%
Otter Tail Corporation	OTTR	$1.34	$45.71	2.93%	3.05%	7.50%	9.00%	n/a	8.25%	10.54%	11.30%	12.06%	10.54%	11.30%	12.06%
PNM Resources, Inc.	PNM	$1.06	$38.30	2.77%	2.85%	7.50%	5.15%	5.10%	5.92%	7.94%	8.77%	10.37%	7.94%	8.77%	10.37%
PPL Corporation	PPL	$1.64	$27.91	5.88%	5.98%	2.00%	2.17%	6.00%	3.39%	7.94%	9.37%	12.05%	7.94%	9.37%	12.05%
Xcel Energy Inc.	XEL	$1.52	$45.09	3.37%	3.47%	5.50%	5.96%	5.80%	5.75%	8.96%	9.22%	9.43%	8.96%	9.22%	9.43%
Mean				3.69%	3.79%	5.46%	5.24%	5.30%	5.39%	8.45%	9.18%	10.12%	8.63%	9.38%	10.12%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

180-DAY CONSTANT GROWTH DCF -- INITIAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
										All Proxy Group			With Exclusions		
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.24	$74.23	3.02%	3.10%	5.00%	6.00%	6.00%	5.67%	8.09%	8.77%	9.11%	8.09%	8.77%	9.11%
Alliant Energy Corporation	LNT	$1.34	$41.31	3.24%	3.34%	6.50%	5.85%	5.60%	5.98%	8.93%	9.32%	9.85%	8.93%	9.32%	9.85%
Ameren Corporation	AEE	$1.83	$58.05	3.15%	3.26%	7.50%	6.30%	6.50%	6.77%	9.55%	10.03%	10.77%	9.55%	10.03%	10.77%
American Electric Power Company, Inc.	AEP	$2.48	$69.31	3.58%	3.67%	4.50%	5.59%	5.60%	5.23%	8.16%	8.90%	9.28%	8.16%	8.90%	9.28%
DTE Energy Company	DTE	$3.53	$104.83	3.37%	3.47%	7.00%	5.67%	5.30%	5.99%	8.76%	9.46%	10.49%	8.76%	9.46%	10.49%
Duke Energy Corporation	DUK	$3.56	$79.47	4.48%	4.58%	5.50%	4.01%	4.60%	4.70%	8.58%	9.29%	10.10%	8.58%	9.29%	10.10%
FirstEnergy Corporation	FE	$1.44	$33.41	4.31%	4.41%	3.00%	Negative	6.00%	4.50%	7.38%	8.91%	10.44%	7.38%	8.91%	10.44%
NorthWestern Corporation	NWE	$2.20	$55.66	3.95%	4.01%	3.50%	2.45%	2.30%	2.75%	6.30%	6.76%	7.52%			7.52%
OGE Energy Corporation	OGE	$1.33	$33.29	4.00%	4.10%	6.00%	4.70%	4.80%	5.17%	8.79%	9.27%	10.12%	8.79%	9.27%	10.12%
Otter Tail Corporation	OTTR	$1.34	$44.53	3.01%	3.13%	7.50%	9.00%	n/a	8.25%	10.62%	11.38%	12.14%	10.62%	11.38%	12.14%
PNM Resources, Inc.	PNM	$1.06	$38.78	2.73%	2.81%	7.50%	5.15%	5.10%	5.92%	7.90%	8.73%	10.34%	7.90%	8.73%	10.34%
PPL Corporation	PPL	$1.64	$29.81	5.50%	5.60%	2.00%	2.17%	6.00%	3.39%	7.56%	8.99%	11.67%	7.56%	8.99%	11.67%
Xcel Energy Inc.	XEL	$1.52	$45.91	3.31%	3.41%	5.50%	5.96%	5.80%	5.75%	8.90%	9.16%	9.37%	8.90%	9.16%	9.37%
Mean				3.67%	3.76%	5.46%	5.24%	5.30%	5.39%	8.42%	9.15%	10.09%	8.60%	9.35%	10.09%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

30-DAY CONSTANT GROWTH DCF -- REFINED PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10] All Proxy Group	[11]	[12]	[13] With Exclusions	[14]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.24	$77.44	2.89%	2.97%	5.00%	6.00%	6.00%	5.67%	7.97%	8.64%	8.98%	7.97%	8.64%	8.98%
Alliant Energy Corporation	LNT	$1.34	$42.48	3.15%	3.25%	6.50%	5.85%	5.60%	5.98%	8.84%	9.23%	9.76%	8.84%	9.23%	9.76%
Ameren Corporation	AEE	$1.83	$60.79	3.01%	3.11%	7.50%	6.30%	6.50%	6.77%	9.41%	9.88%	10.62%	9.41%	9.88%	10.62%
American Electric Power Company, Inc.	AEP	$2.48	$69.75	3.56%	3.65%	4.50%	5.59%	5.60%	5.23%	8.14%	8.88%	9.26%	8.14%	8.88%	9.26%
DTE Energy Company	DTE	$3.53	$105.08	3.36%	3.46%	7.00%	5.67%	5.30%	5.99%	8.75%	9.45%	10.48%	8.75%	9.45%	10.48%
FirstEnergy Corporation	FE	$1.44	$35.62	4.04%	4.13%	3.00%	Negative	6.00%	4.50%	7.10%	8.63%	10.16%	7.10%	8.63%	10.16%
OGE Energy Corporation	OGE	$1.33	$35.36	3.76%	3.86%	6.00%	4.70%	4.80%	5.17%	8.55%	9.03%	9.87%	8.55%	9.03%	9.87%
Otter Tail Corporation	OTTR	$1.34	$48.24	2.78%	2.89%	7.50%	9.00%	n/a	8.25%	10.38%	11.14%	11.90%	10.38%	11.14%	11.90%
PPL Corporation	PPL	$1.64	$28.49	5.76%	5.85%	2.00%	2.17%	6.00%	3.39%	7.81%	9.24%	11.93%	7.81%	9.24%	11.93%
Mean				3.59%	3.69%	5.44%	5.66%	5.73%	5.66%	8.55%	9.35%	10.33%	8.55%	9.35%	10.33%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

90-DAY CONSTANT GROWTH DCF -- REFINED PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.24	$75.35	2.97%	3.06%	5.00%	6.00%	6.00%	5.67%	8.05%	8.72%	9.06%	8.05%	8.72%	9.06%
Alliant Energy Corporation	LNT	$1.34	$41.50	3.23%	3.33%	6.50%	5.85%	5.60%	5.98%	8.92%	9.31%	9.83%	8.92%	9.31%	9.83%
Ameren Corporation	AEE	$1.83	$58.27	3.14%	3.25%	7.50%	6.30%	6.50%	6.77%	9.54%	10.01%	10.76%	9.54%	10.01%	10.76%
American Electric Power Company, Inc.	AEP	$2.48	$68.07	3.64%	3.74%	4.50%	5.59%	5.60%	5.23%	8.23%	8.97%	9.35%	8.23%	8.97%	9.35%
DTE Energy Company	DTE	$3.53	$102.94	3.43%	3.53%	7.00%	5.67%	5.30%	5.99%	8.82%	9.52%	10.55%	8.82%	9.52%	10.55%
FirstEnergy Corporation	FE	$1.44	$34.56	4.17%	4.26%	3.00%	Negative	6.00%	4.50%	7.23%	8.76%	10.29%	7.23%	8.76%	10.29%
OGE Energy Corporation	OGE	$1.33	$33.97	3.92%	4.02%	6.00%	4.70%	4.80%	5.17%	8.71%	9.18%	10.03%	8.71%	9.18%	10.03%
Otter Tail Corporation	OTTR	$1.34	$45.71	2.93%	3.05%	7.50%	9.00%	n/a	8.25%	10.54%	11.30%	12.06%	10.54%	11.30%	12.06%
PPL Corporation	PPL	$1.64	$27.91	5.88%	5.98%	2.00%	2.17%	6.00%	3.39%	7.94%	9.37%	12.05%	7.94%	9.37%	12.05%
Mean				3.70%	3.80%	5.44%	5.66%	5.73%	5.66%	8.66%	9.46%	10.44%	8.66%	9.46%	10.44%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

180-DAY CONSTANT GROWTH DCF -- REFINED PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	All Proxy Group [9]	[10]	[11]	With Exclusions [12]	[13]	[14]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.24	$74.23	3.02%	3.10%	5.00%	6.00%	6.00%	5.67%	8.09%	8.77%	9.11%	8.09%	8.77%	9.11%
Alliant Energy Corporation	LNT	$1.34	$41.31	3.24%	3.34%	6.50%	5.85%	5.60%	5.98%	8.93%	9.32%	9.85%	8.93%	9.32%	9.85%
Ameren Corporation	AEE	$1.83	$58.05	3.15%	3.26%	7.50%	6.30%	6.50%	6.77%	9.55%	10.03%	10.77%	9.55%	10.03%	10.77%
American Electric Power Company, Inc.	AEP	$2.48	$69.31	3.58%	3.67%	4.50%	5.59%	5.60%	5.23%	8.16%	8.90%	9.28%	8.16%	8.90%	9.28%
DTE Energy Company	DTE	$3.53	$104.83	3.37%	3.47%	7.00%	5.67%	5.30%	5.99%	8.76%	9.46%	10.49%	8.76%	9.46%	10.49%
FirstEnergy Corporation	FE	$1.44	$33.41	4.31%	4.41%	3.00%	Negative	6.00%	4.50%	7.38%	8.91%	10.44%	7.38%	8.91%	10.44%
OGE Energy Corporation	OGE	$1.33	$33.29	4.00%	4.10%	6.00%	4.70%	4.80%	5.17%	8.79%	9.27%	10.12%	8.79%	9.27%	10.12%
Otter Tail Corporation	OTTR	$1.34	$44.53	3.01%	3.13%	7.50%	9.00%	n/a	8.25%	10.62%	11.38%	12.14%	10.62%	11.38%	12.14%
PPL Corporation	PPL	$1.64	$29.81	5.50%	5.60%	2.00%	2.17%	6.00%	3.39%	7.56%	8.99%	11.67%	7.56%	8.99%	11.67%
Mean				3.69%	3.79%	5.44%	5.66%	5.73%	5.66%	8.65%	9.45%	10.43%	8.65%	9.45%	10.43%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

PROJECTED CONSTANT GROWTH DCF -- INITIAL PROXY GROUP

			Stock Price (2021 - 2023)									All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company		Annualized Dividend (2021-2023)	High	Low	Mean	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.70	$75.00	$55.00	$65.00	4.15%	4.27%	5.00%	6.00%	6.00%	5.67%	9.26%	9.94%	10.28%	9.26%	9.94%	10.28%
Alliant Energy Corporation	LNT	$1.66	$45.00	$35.00	$40.00	4.15%	4.27%	6.50%	5.85%	5.60%	5.98%	9.87%	10.26%	10.78%	9.87%	10.26%	10.78%
Ameren Corporation	AEE	$2.35	$65.00	$50.00	$57.50	4.09%	4.23%	7.50%	6.30%	6.50%	6.77%	10.52%	10.99%	11.74%	10.52%	10.99%	11.74%
American Electric Power Company, Inc.	AEP	$3.05	$80.00	$65.00	$72.50	4.21%	4.32%	4.50%	5.59%	5.60%	5.23%	8.80%	9.55%	9.92%	8.80%	9.55%	9.92%
DTE Energy Company	DTE	$4.55	$125.00	$90.00	$107.50	4.23%	4.36%	7.00%	5.67%	5.30%	5.99%	9.64%	10.35%	11.38%	9.64%	10.35%	11.38%
Duke Energy Corporation	DUK	$4.40	$110.00	$85.00	$97.50	4.51%	4.62%	5.50%	4.01%	4.60%	4.70%	8.61%	9.32%	10.14%	8.61%	9.32%	10.14%
FirstEnergy Corporation	FE	$1.60	$50.00	$30.00	$40.00	4.00%	4.09%	3.00%	Negative	6.00%	4.50%	7.06%	8.59%	10.12%	7.06%	8.59%	10.12%
NorthWestern Corporation	NWE	$2.60	$75.00	$55.00	$65.00	4.00%	4.06%	3.50%	2.45%	2.30%	2.75%	6.35%	6.81%	7.57%			7.57%
OGE Energy Corporation	OGE	$1.85	$50.00	$35.00	$42.50	4.35%	4.47%	6.00%	4.70%	4.80%	5.17%	9.16%	9.63%	10.48%	9.16%	9.63%	10.48%
Otter Tail Corporation	OTTR	$1.55	$55.00	$40.00	$47.50	3.26%	3.40%	7.50%	9.00%	n/a	8.25%	10.89%	11.65%	12.41%	10.89%	11.65%	12.41%
PNM Resources, Inc.	PNM	$1.35	$40.00	$25.00	$32.50	4.15%	4.28%	7.50%	5.15%	5.10%	5.92%	9.36%	10.19%	11.81%	9.36%	10.19%	11.81%
PPL Corporation	PPL	$1.80	$45.00	$35.00	$40.00	4.50%	4.58%	2.00%	2.17%	6.00%	3.39%	6.55%	7.97%	10.64%		7.97%	10.64%
Xcel Energy Inc.	XEL	$1.90	$50.00	$45.00	$47.50	4.00%	4.12%	5.50%	5.96%	5.80%	5.75%	9.61%	9.87%	10.08%	9.61%	9.87%	10.08%
Mean						4.12%	4.23%	5.46%	5.24%	5.30%	5.39%	8.90%	9.62%	10.57%	9.34%	9.86%	10.57%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals Average ([2], [3])
[5] Equals [1] / [4]
[6] Equals [5] x (1 + 0.50 x [10])
[7] Source: Value Line
[8] Source: Yahoo! Finance
[9] Source: Zacks
[10] Equals Average ([7], [8], [9])
[11] Equals [5] x (1 + 0.50 x Minimum ([7], [8], [9]) + Minimum ([7], [8], [9])
[12] Equals [6] + [10]
[13] Equals [5] x (1 + 0.50 x Maximum ([7], [8], [9]) + Maximum ([7], [8], [9])
[14] Equals [11] if greater than 7.00%
[15] Equals [12] if greater than 7.00%
[16] Equals [13] if greater than 7.00%

PROJECTED CONSTANT GROWTH DCF -- REFINED PROXY GROUP

												All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company		Annualized Dividend (2021-2023)	Stock Price (2021 - 2023) High	Low	Mean	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.70	$75.00	$55.00	$65.00	4.15%	4.27%	5.00%	6.00%	6.00%	5.67%	9.26%	9.94%	10.28%	9.26%	9.94%	10.28%
Alliant Energy Corporation	LNT	$1.66	$45.00	$35.00	$40.00	4.15%	4.27%	6.50%	5.85%	5.60%	5.98%	9.87%	10.26%	10.78%	9.87%	10.26%	10.78%
Ameren Corporation	AEE	$2.35	$65.00	$50.00	$57.50	4.09%	4.23%	7.50%	6.30%	6.50%	6.77%	10.52%	10.99%	11.74%	10.52%	10.99%	11.74%
American Electric Power Company, Inc.	AEP	$3.05	$80.00	$65.00	$72.50	4.21%	4.32%	4.50%	5.59%	5.60%	5.23%	8.80%	9.55%	9.92%	8.80%	9.55%	9.92%
DTE Energy Company	DTE	$4.55	$125.00	$90.00	$107.50	4.23%	4.36%	7.00%	5.67%	5.30%	5.99%	9.64%	10.35%	11.38%	9.64%	10.35%	11.38%
FirstEnergy Corporation	FE	$1.60	$50.00	$30.00	$40.00	4.00%	4.09%	3.00%	Negative	6.00%	4.50%	7.06%	8.59%	10.12%	7.06%	8.59%	10.12%
OGE Energy Corporation	OGE	$1.85	$50.00	$35.00	$42.50	4.35%	4.47%	6.00%	4.70%	4.80%	5.17%	9.16%	9.63%	10.48%	9.16%	9.63%	10.48%
Otter Tail Corporation	OTTR	$1.55	$55.00	$40.00	$47.50	3.26%	3.40%	7.50%	9.00%	n/a	8.25%	10.89%	11.65%	12.41%	10.89%	11.65%	12.41%
PPL Corporation	PPL	$1.80	$45.00	$35.00	$40.00	4.50%	4.58%	2.00%	2.17%	6.00%	3.39%	6.55%	7.97%	10.64%		7.97%	10.64%
Mean						4.11%	4.22%	5.44%	5.66%	5.73%	5.66%	9.08%	9.88%	10.86%	9.40%	9.88%	10.86%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals Average ([2], [3])
[5] Equals [1] / [4]
[6] Equals [5] x (1 + 0.50 x [10])
[7] Source: Value Line
[8] Source: Yahoo! Finance
[9] Source: Zacks
[10] Equals Average ([7], [8], [9])
[11] Equals [5] x (1 + 0.50 x Minimum ([7], [8], [9]) + Minimum ([7], [8], [9])
[12] Equals [6] + [10]
[13] Equals [5] x (1 + 0.50 x Maximum ([7], [8], [9]) + Maximum ([7], [8], [9])
[14] Equals [11] if greater than 7.00%
[15] Equals [12] if greater than 7.00%
[16] Equals [13] if greater than 7.00%

BETA -- INITIAL PROXY GROUP
AS OF JULY 31, 2018

Proxy Group		[1] Value Line
ALLETE, Inc.	ALE	0.75
Alliant Energy Corporation	LNT	0.70
Ameren Corporation	AEE	0.65
American Electric Power Company, Inc.	AEP	0.65
DTE Energy Company	DTE	0.65
Duke Energy Corporation	DUK	0.60
FirstEnergy Corporation	FE	0.65
NorthWestern Corporation	NWE	0.65
OGE Energy Corporation	OGE	0.95
Otter Tail Corporation	OTTR	0.85
PNM Resources, Inc.	PNM	0.75
PPL Corporation	PPL	0.75
Xcel Energy Inc.	XEL	0.60
Mean		0.71

Notes:
[1] Sources: Value Line, dated May 18, June 15, July 27, 2018

BETA -- REFINED PROXY GROUP
AS OF JULY 31, 2018

		[1]
Proxy Group		Value Line
ALLETE, Inc.	ALE	0.75
Alliant Energy Corporation	LNT	0.70
Ameren Corporation	AEE	0.65
American Electric Power Company, Inc.	AEP	0.65
DTE Energy Company	DTE	0.65
FirstEnergy Corporation	FE	0.65
OGE Energy Corporation	OGE	0.95
Otter Tail Corporation	OTTR	0.85
PPL Corporation	PPL	0.75
Mean		0.73

Notes:
[1] Sources: Value Line, dated May 18, June 15, July 27, 2018

CAPITAL ASSET PRICING MODEL -- INITIAL PROXY GROUP

	[3]	[4]	[5]	[6]	[7]
	Risk-Free Rate *(Rf)*	Beta *(β)*	Market Return *(Rm)*	Market Risk Premium *(Rm − Rf)*	ROE *(K)*
Proxy Group Average Value Line Beta					
Near-term projected 30-year U.S. Treasury bond yield (Q4 2018 - Q4 2019) [1]	3.56%	0.708	15.10%	11.54%	11.73%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [2]	4.20%	0.708	15.10%	10.90%	11.91%
				MEAN	11.82%

CAPITAL ASSET PRICING MODEL -- REFINED PROXY GROUP

	[3]	[4]	[5]	[6]	[7]
	Risk-Free Rate *(Rf)*	Beta *(β)*	Market Return *(Rm)*	Market Risk Premium *(Rm − Rf)*	ROE *(K)*
Proxy Group Average Value Line Beta					
Near-term projected 30-year U.S. Treasury bond yield (Q4 2018 - Q4 2019) [1]	3.56%	0.733	15.10%	11.54%	12.02%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [2]	4.20%	0.733	15.10%	10.90%	12.19%
				MEAN	12.11%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 37, No. 8, August 1, 2018, at 2
[2] Source: Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, at 14
[3] See Notes [1] and [2]
[4] Source: Schedule-9 and Schedule-10
[5] Source: Schedule-11, at 2
[6] Equals [5] - [3]
[7] Equals [3] + ([4] x [6])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[8] Estimated Weighted Average Dividend Yield	1.91%	
[9] Estimated Weighted Average Long-Term Growth Rate	13.06%	
[10] S&P 500 Estimated Required Market Return	15.10%	
[11] Risk-Free Rate	3.56%	4.20%
[12] Implied Market Risk Premium	11.54%	10.90%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	0.18%	3.61%	0.01%	7.60%	0.01%
American Express Co	AXP	0.35%	1.41%	0.00%	17.30%	0.06%
Verizon Communications Inc	VZ	0.86%	4.57%	0.04%	1.41%	0.01%
Broadcom Inc	AVGO	0.39%	3.16%	0.01%	13.01%	0.05%
Boeing Co/The	BA	0.83%	1.92%	0.02%	15.33%	0.13%
Caterpillar Inc	CAT	0.35%	2.39%	0.01%	25.37%	0.09%
JPMorgan Chase & Co	JPM	1.58%	1.95%	0.03%	9.80%	0.16%
Chevron Corp	CVX	0.98%	3.55%	0.03%	6.76%	0.07%
Coca-Cola Co/The	KO	0.80%	3.35%	0.03%	7.85%	0.06%
AbbVie Inc	ABBV	0.56%	4.16%	0.02%	11.19%	0.06%
Walt Disney Co/The	DIS	0.68%	1.48%	0.01%	13.80%	0.09%
FleetCor Technologies Inc	FLT	0.08%	n/a	n/a	16.50%	0.01%
Extra Space Storage Inc	EXR	0.05%	3.66%	0.00%	6.08%	0.00%
Exxon Mobil Corp	XOM	1.40%	4.02%	0.06%	11.54%	0.16%
Phillips 66	PSX	0.23%	2.59%	0.01%	5.55%	0.01%
General Electric Co	GE	0.48%	3.52%	0.02%	3.67%	0.02%
HP Inc	HPQ	0.15%	2.41%	0.00%	5.45%	0.01%
Home Depot Inc/The	HD	0.92%	2.09%	0.02%	13.25%	0.12%
International Business Machines Corp	IBM	0.53%	4.33%	0.02%	2.40%	0.01%
Concho Resources Inc	CXO	0.12%	n/a	n/a	32.85%	0.04%
Johnson & Johnson	JNJ	1.44%	2.72%	0.04%	7.49%	0.11%
McDonald's Corp	MCD	0.50%	2.56%	0.01%	8.72%	0.04%
Merck & Co Inc	MRK	0.72%	2.91%	0.02%	7.25%	0.05%
3M Co	MMM	0.50%	2.56%	0.01%	8.70%	0.04%
American Water Works Co Inc	AWK	0.06%	2.06%	0.00%	8.08%	0.01%
Bank of America Corp	BAC	1.25%	1.94%	0.02%	13.40%	0.17%
Brighthouse Financial Inc	BHF	0.02%	n/a	n/a	8.00%	0.00%
Baker Hughes a GE Co	BHGE	0.06%	2.08%	0.00%	33.00%	0.02%
Pfizer Inc	PFE	0.94%	3.41%	0.03%	6.51%	0.06%
Procter & Gamble Co/The	PG	0.82%	3.55%	0.03%	7.24%	0.06%
AT&T Inc	T	0.94%	6.26%	0.06%	-0.50%	0.00%
Travelers Cos Inc/The	TRV	0.14%	2.37%	0.00%	17.85%	0.03%
United Technologies Corp	UTX	0.44%	2.06%	0.01%	10.59%	0.05%
Analog Devices Inc	ADI	0.14%	2.00%	0.00%	9.47%	0.01%
Walmart Inc	WMT	1.06%	2.33%	0.02%	6.83%	0.07%
Cisco Systems Inc	CSCO	0.80%	3.12%	0.03%	7.16%	0.06%
Intel Corp	INTC	0.90%	2.49%	0.02%	8.98%	0.08%
General Motors Co	GM	0.22%	4.01%	0.01%	10.78%	0.02%
Microsoft Corp	MSFT	3.29%	1.58%	0.05%	10.76%	0.35%
Dollar General Corp	DG	0.11%	1.18%	0.00%	15.96%	0.02%
Kinder Morgan Inc/DE	KMI	0.16%	4.50%	0.01%	86.15%	0.14%
Citigroup Inc	C	0.73%	2.50%	0.02%	14.46%	0.11%
American International Group Inc	AIG	0.20%	2.32%	0.00%	11.00%	0.02%
Honeywell International Inc	HON	0.48%	1.87%	0.01%	11.21%	0.05%
Altria Group Inc	MO	0.45%	4.77%	0.02%	4.87%	0.02%
HCA Healthcare Inc	HCA	0.18%	1.13%	0.00%	13.58%	0.02%
Under Armour Inc	UAA	0.02%	n/a	n/a	25.41%	0.00%
International Paper Co	IP	0.09%	3.54%	0.00%	7.90%	0.01%
Hewlett Packard Enterprise Co	HPE	0.09%	2.91%	0.00%	-4.05%	0.00%
Abbott Laboratories	ABT	0.46%	1.71%	0.01%	13.00%	0.06%
Aflac Inc	AFL	0.14%	2.23%	0.00%	8.45%	0.01%
Air Products & Chemicals Inc	APD	0.15%	2.68%	0.00%	11.92%	0.02%
Royal Caribbean Cruises Ltd	RCL	0.10%	2.13%	0.00%	15.52%	0.01%
American Electric Power Co Inc	AEP	0.14%	3.49%	0.00%	5.47%	0.01%
Hess Corp	HES	0.08%	1.52%	0.00%	-9.34%	-0.01%
Anadarko Petroleum Corp	APC	0.15%	1.37%	0.00%	19.24%	0.03%
Aon PLC	AON	0.14%	1.11%	0.00%	11.42%	0.02%
Apache Corp	APA	0.07%	2.17%	0.00%	-17.07%	-0.01%
Archer-Daniels-Midland Co	ADM	0.11%	2.78%	0.00%	11.40%	0.01%
Automatic Data Processing Inc	ADP	0.24%	2.04%	0.00%	11.67%	0.03%
Verisk Analytics Inc	VRSK	0.07%	n/a	n/a	12.84%	0.01%
AutoZone Inc	AZO	0.08%	n/a	n/a	12.87%	0.01%
Avery Dennison Corp	AVY	0.04%	1.81%	0.00%	10.37%	0.00%
MSCI Inc	MSCI	0.06%	0.91%	0.00%	10.00%	0.01%
Ball Corp	BLL	0.06%	1.03%	0.00%	5.50%	0.00%
Bank of New York Mellon Corp/The	BK	0.22%	2.09%	0.00%	7.80%	0.02%
Baxter International Inc	BAX	0.16%	1.05%	0.00%	13.06%	0.02%
Becton Dickinson and Co	BDX	0.27%	1.20%	0.00%	14.72%	0.04%
Berkshire Hathaway Inc	BRK/B	1.08%	n/a	n/a	1.40%	0.02%
Best Buy Co Inc	BBY	0.08%	2.40%	0.00%	11.22%	0.01%
H&R Block Inc	HRB	0.02%	3.97%	0.00%	11.00%	0.00%
Boston Scientific Corp	BSX	0.19%	n/a	n/a	21.44%	0.04%
Bristol-Myers Squibb Co	BMY	0.39%	2.72%	0.01%	9.37%	0.04%
Fortune Brands Home & Security Inc	FBHS	0.03%	1.38%	0.00%	12.83%	0.00%
Brown-Forman Corp	BF/B	0.07%	1.19%	0.00%	12.85%	0.01%
Cabot Oil & Gas Corp	COG	0.04%	1.02%	0.00%	39.81%	0.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Campbell Soup Co	CPB	0.05%	3.42%	0.00%	3.30%	0.00%
Kansas City Southern	KSU	0.05%	1.24%	0.00%	8.70%	0.00%
Advanced Micro Devices Inc	AMD	0.07%	n/a	n/a	23.40%	0.02%
Hilton Worldwide Holdings Inc	HLT	0.09%	0.76%	0.00%	11.20%	0.01%
Carnival Corp	CCL	0.13%	3.38%	0.00%	13.80%	0.02%
Qorvo Inc	QRVO	0.04%	n/a	n/a	13.06%	0.01%
CenturyLink Inc	CTL	0.08%	11.51%	0.01%	-15.40%	-0.01%
Cigna Corp	CI	0.18%	0.02%	0.00%	11.84%	0.02%
UDR Inc	UDR	0.04%	3.35%	0.00%	5.51%	0.00%
Clorox Co/The	CLX	0.07%	2.84%	0.00%	8.51%	0.01%
CMS Energy Corp	CMS	0.06%	2.96%	0.00%	6.16%	0.00%
Colgate-Palmolive Co	CL	0.24%	2.51%	0.01%	7.97%	0.02%
Comerica Inc	CMA	0.07%	2.48%	0.00%	21.22%	0.01%
IPG Photonics Corp	IPGP	0.04%	n/a	n/a	12.00%	0.00%
CA Inc	CA	0.07%	2.31%	0.00%	3.10%	0.00%
Conagra Brands Inc	CAG	0.06%	2.32%	0.00%	7.85%	0.00%
Consolidated Edison Inc	ED	0.10%	3.62%	0.00%	3.00%	0.00%
SL Green Realty Corp	SLG	0.04%	3.15%	0.00%	4.48%	0.00%
Corning Inc	GLW	0.11%	2.17%	0.00%	8.73%	0.01%
Cummins Inc	CMI	0.09%	3.19%	0.00%	9.06%	0.01%
Danaher Corp	DHR	0.29%	0.62%	0.00%	8.39%	0.02%
Target Corp	TGT	0.17%	3.17%	0.01%	5.22%	0.01%
Deere & Co	DE	0.19%	1.91%	0.00%	7.33%	0.01%
Dominion Energy Inc	D	0.19%	4.66%	0.01%	5.53%	0.01%
Dover Corp	DOV	0.05%	2.27%	0.00%	12.63%	0.01%
Cboe Global Markets Inc	CBOE	0.04%	1.11%	0.00%	13.64%	0.01%
Duke Energy Corp	DUK	0.23%	4.55%	0.01%	4.27%	0.01%
Eaton Corp PLC	ETN	0.15%	3.17%	0.00%	8.92%	0.01%
Ecolab Inc	ECL	0.16%	1.17%	0.00%	13.30%	0.02%
PerkinElmer Inc	PKI	0.04%	0.35%	0.00%	16.47%	0.01%
Emerson Electric Co	EMR	0.18%	2.68%	0.00%	11.91%	0.02%
EOG Resources Inc	EOG	0.30%	0.57%	0.00%	9.50%	0.03%
Entergy Corp	ETR	0.06%	4.38%	0.00%	2.86%	0.00%
Equifax Inc	EFX	0.06%	1.24%	0.00%	7.43%	0.00%
EQT Corp	EQT	0.05%	0.24%	0.00%	17.50%	0.01%
IQVIA Holdings Inc	IQV	0.10%	n/a	n/a	14.95%	0.01%
XL Group Ltd	XL	0.06%	1.57%	0.00%	n/a	n/a
Gartner Inc	IT	0.05%	n/a	n/a	15.00%	0.01%
FedEx Corp	FDX	0.26%	1.06%	0.00%	15.40%	0.04%
Macy's Inc	M	0.05%	3.80%	0.00%	0.10%	0.00%
FMC Corp	FMC	0.05%	0.73%	0.00%	16.25%	0.01%
Ford Motor Co	F	0.16%	5.98%	0.01%	-7.42%	-0.01%
NextEra Energy Inc	NEE	0.32%	2.65%	0.01%	8.88%	0.03%
Franklin Resources Inc	BEN	0.07%	2.68%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.10%	1.21%	0.00%	0.25%	0.00%
Gap Inc/The	GPS	0.05%	3.22%	0.00%	9.25%	0.00%
General Dynamics Corp	GD	0.24%	1.86%	0.00%	11.21%	0.03%
General Mills Inc	GIS	0.11%	4.26%	0.00%	9.00%	0.01%
Genuine Parts Co	GPC	0.06%	2.96%	0.00%	5.68%	0.00%
WW Grainger Inc	GWW	0.08%	1.57%	0.00%	14.87%	0.01%
Halliburton Co	HAL	0.15%	1.70%	0.00%	74.00%	0.11%
Harley-Davidson Inc	HOG	0.03%	3.45%	0.00%	8.25%	0.00%
Harris Corp	HRS	0.08%	1.38%	0.00%	n/a	n/a
HCP Inc	HCP	0.05%	5.71%	0.00%	-0.44%	0.00%
Helmerich & Payne Inc	HP	0.03%	4.63%	0.00%	122.99%	0.03%
Fortive Corp	FTV	0.12%	0.34%	0.00%	13.63%	0.02%
Hershey Co/The	HSY	0.06%	2.94%	0.00%	8.10%	0.00%
Synchrony Financial	SYF	0.09%	2.90%	0.00%	7.35%	0.01%
Hormel Foods Corp	HRL	0.08%	2.09%	0.00%	8.05%	0.01%
Arthur J Gallagher & Co	AJG	0.05%	2.30%	0.00%	10.32%	0.01%
Mondelez International Inc	MDLZ	0.26%	2.40%	0.01%	10.26%	0.03%
CenterPoint Energy Inc	CNP	0.05%	3.90%	0.00%	5.99%	0.00%
Humana Inc	HUM	0.17%	0.64%	0.00%	13.13%	0.02%
Willis Towers Watson PLC	WLTW	0.08%	1.51%	0.00%	10.00%	0.01%
Illinois Tool Works Inc	ITW	0.20%	2.18%	0.00%	10.13%	0.02%
Ingersoll-Rand PLC	IR	0.10%	2.15%	0.00%	11.44%	0.01%
Foot Locker Inc	FL	0.02%	2.83%	0.00%	4.87%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.03%	3.73%	0.00%	6.31%	0.00%
International Flavors & Fragrances Inc	IFF	0.04%	2.08%	0.00%	9.40%	0.00%
Jacobs Engineering Group Inc	JEC	0.04%	0.89%	0.00%	19.36%	0.01%
Hanesbrands Inc	HBI	0.03%	2.70%	0.00%	6.15%	0.00%
Kellogg Co	K	0.10%	3.15%	0.00%	8.02%	0.01%
Broadridge Financial Solutions Inc	BR	0.05%	1.29%	0.00%	10.00%	0.01%
Perrigo Co PLC	PRGO	0.05%	0.94%	0.00%	7.20%	0.00%
Kimberly-Clark Corp	KMB	0.16%	3.51%	0.01%	6.46%	0.01%
Kimco Realty Corp	KIM	0.03%	6.71%	0.00%	2.90%	0.00%
Kohl's Corp	KSS	0.05%	3.30%	0.00%	6.93%	0.00%
Oracle Corp	ORCL	0.77%	1.59%	0.01%	7.44%	0.06%
Kroger Co/The	KR	0.09%	1.93%	0.00%	6.46%	0.01%
Leggett & Platt Inc	LEG	0.02%	3.49%	0.00%	10.00%	0.00%
Lennar Corp	LEN	0.06%	0.31%	0.00%	21.15%	0.01%
Jefferies Financial Group Inc	JEF	0.03%	2.06%	0.00%	18.00%	0.01%
Eli Lilly & Co	LLY	0.43%	2.28%	0.01%	11.65%	0.05%
L Brands Inc	LB	0.04%	7.58%	0.00%	9.33%	0.00%
Charter Communications Inc	CHTR	0.29%	n/a	n/a	29.32%	0.08%
Lincoln National Corp	LNC	0.06%	1.94%	0.00%	n/a	n/a
Loews Corp	L	0.06%	0.49%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.33%	1.93%	0.01%	15.34%	0.05%
Host Hotels & Resorts Inc	HST	0.06%	3.82%	0.00%	3.98%	0.00%
Marsh & McLennan Cos Inc	MMC	0.17%	1.99%	0.00%	14.91%	0.03%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Masco Corp	MAS	0.05%	1.04%	0.00%	15.99%	0.01%
Mattel Inc	MAT	0.02%	n/a	n/a	10.00%	0.00%
S&P Global Inc	SPGI	0.20%	1.00%	0.00%	11.60%	0.02%
Medtronic PLC	MDT	0.49%	2.22%	0.01%	7.07%	0.03%
CVS Health Corp	CVS	0.27%	3.08%	0.01%	11.14%	0.03%
DowDuPont Inc	DWDP	0.65%	2.21%	0.01%	8.35%	0.05%
Micron Technology Inc	MU	0.25%	n/a	n/a	3.70%	0.01%
Motorola Solutions Inc	MSI	0.08%	1.71%	0.00%	7.30%	0.01%
Mylan NV	MYL	0.08%	n/a	n/a	6.37%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	8.95%	0.01%
Newell Brands Inc	NWL	0.05%	3.51%	0.00%	5.30%	0.00%
Newmont Mining Corp	NEM	0.08%	1.53%	0.00%	-3.00%	0.00%
Twenty-First Century Fox Inc	FOXA	0.19%	0.80%	0.00%	9.95%	0.02%
NIKE Inc	NKE	0.40%	1.04%	0.00%	13.66%	0.05%
NiSource Inc	NI	0.04%	2.98%	0.00%	5.63%	0.00%
Noble Energy Inc	NBL	0.07%	1.22%	0.00%	13.76%	0.01%
Norfolk Southern Corp	NSC	0.19%	1.89%	0.00%	14.38%	0.03%
Principal Financial Group Inc	PFG	0.07%	3.65%	0.00%	7.93%	0.01%
Eversource Energy	ES	0.08%	3.33%	0.00%	5.98%	0.00%
Northrop Grumman Corp	NOC	0.21%	1.60%	0.00%	16.35%	0.03%
Wells Fargo & Co	WFC	1.12%	3.00%	0.03%	13.41%	0.15%
Nucor Corp	NUE	0.09%	2.27%	0.00%	5.65%	0.00%
PVH Corp	PVH	0.05%	0.10%	0.00%	10.51%	0.01%
Occidental Petroleum Corp	OXY	0.26%	3.72%	0.01%	11.55%	0.03%
Omnicom Group Inc	OMC	0.06%	3.49%	0.00%	5.44%	0.00%
ONEOK Inc	OKE	0.12%	4.68%	0.01%	25.16%	0.03%
Raymond James Financial Inc	RJF	0.05%	1.31%	0.00%	17.00%	0.01%
PG&E Corp	PCG	0.09%	n/a	n/a	5.25%	0.00%
Parker-Hannifin Corp	PH	0.09%	1.80%	0.00%	9.59%	0.01%
PPL Corp	PPL	0.08%	5.70%	0.00%	8.10%	0.01%
Exelon Corp	EXC	0.17%	3.25%	0.01%	5.29%	0.01%
ConocoPhillips	COP	0.34%	1.58%	0.01%	6.00%	0.02%
PulteGroup Inc	PHM	0.03%	1.26%	0.00%	21.34%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.46%	0.00%	4.49%	0.00%
PNC Financial Services Group Inc/The	PNC	0.27%	2.62%	0.01%	9.79%	0.03%
PPG Industries Inc	PPG	0.11%	1.74%	0.00%	8.06%	0.01%
Praxair Inc	PX	0.19%	1.97%	0.00%	13.90%	0.03%
Progressive Corp/The	PGR	0.14%	1.87%	0.00%	9.20%	0.01%
Public Service Enterprise Group Inc	PEG	0.11%	3.49%	0.00%	6.54%	0.01%
Raytheon Co	RTN	0.23%	1.75%	0.00%	14.87%	0.03%
Robert Half International Inc	RHI	0.04%	1.48%	0.00%	17.10%	0.01%
SCANA Corp	SCG	0.02%	1.24%	0.00%	-2.12%	0.00%
Edison International	EIX	0.09%	3.63%	0.00%	5.37%	0.00%
Schlumberger Ltd	SLB	0.38%	2.96%	0.01%	35.00%	0.13%
Charles Schwab Corp/The	SCHW	0.28%	1.02%	0.00%	20.68%	0.06%
Sherwin-Williams Co/The	SHW	0.17%	0.78%	0.00%	11.42%	0.02%
JM Smucker Co/The	SJM	0.05%	3.06%	0.00%	5.05%	0.00%
Snap-on Inc	SNA	0.04%	1.93%	0.00%	9.30%	0.00%
AMETEK Inc	AME	0.07%	0.72%	0.00%	11.81%	0.01%
Southern Co/The	SO	0.20%	4.94%	0.01%	4.38%	0.01%
BB&T Corp	BBT	0.16%	3.19%	0.01%	14.92%	0.02%
Southwest Airlines Co	LUV	0.14%	1.10%	0.00%	11.17%	0.02%
Stanley Black & Decker Inc	SWK	0.09%	1.77%	0.00%	10.65%	0.01%
Public Storage	PSA	0.15%	3.67%	0.01%	5.50%	0.01%
SunTrust Banks Inc	STI	0.14%	2.22%	0.00%	14.78%	0.02%
Sysco Corp	SYY	0.14%	2.14%	0.00%	11.85%	0.02%
Andeavor	ANDV	0.09%	1.57%	0.00%	7.95%	0.01%
Texas Instruments Inc	TXN	0.44%	2.23%	0.01%	11.05%	0.05%
Textron Inc	TXT	0.07%	0.12%	0.00%	13.71%	0.01%
Thermo Fisher Scientific Inc	TMO	0.38%	0.29%	0.00%	11.50%	0.04%
Tiffany & Co	TIF	0.07%	1.60%	0.00%	12.94%	0.01%
TJX Cos Inc/The	TJX	0.25%	1.60%	0.00%	10.70%	0.03%
Torchmark Corp	TMK	0.04%	0.73%	0.00%	13.17%	0.01%
Total System Services Inc	TSS	0.07%	0.57%	0.00%	14.62%	0.01%
Johnson Controls International plc	JCI	0.14%	2.77%	0.00%	11.20%	0.02%
Ulta Beauty Inc	ULTA	0.06%	n/a	n/a	17.33%	0.01%
Union Pacific Corp	UNP	0.45%	2.13%	0.01%	14.20%	0.06%
UnitedHealth Group Inc	UNH	0.98%	1.42%	0.01%	13.06%	0.13%
Unum Group	UNM	0.04%	2.62%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.07%	0.95%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	12.05%	0.01%
Ventas Inc	VTR	0.08%	5.60%	0.00%	1.95%	0.00%
VF Corp	VFC	0.15%	2.00%	0.00%	8.16%	0.01%
Vornado Realty Trust	VNO	0.06%	3.50%	0.00%	7.45%	0.00%
Vulcan Materials Co	VMC	0.06%	1.00%	0.00%	20.36%	0.01%
Weyerhaeuser Co	WY	0.10%	3.74%	0.00%	10.60%	0.01%
Whirlpool Corp	WHR	0.03%	3.51%	0.00%	9.46%	0.00%
Williams Cos Inc/The	WMB	0.10%	4.57%	0.00%	-12.20%	-0.01%
WEC Energy Group Inc	WEC	0.08%	3.33%	0.00%	3.00%	0.00%
Xerox Corp	XRX	0.03%	3.85%	0.00%	2.05%	0.00%
Adobe Systems Inc	ADBE	0.48%	n/a	n/a	18.66%	0.09%
AES Corp/VA	AES	0.04%	3.89%	0.00%	8.19%	0.00%
Amgen Inc	AMGN	0.51%	2.69%	0.01%	6.55%	0.03%
Apple Inc	AAPL	3.73%	1.53%	0.06%	11.47%	0.43%
Autodesk Inc	ADSK	0.11%	n/a	n/a	34.00%	0.04%
Cintas Corp	CTAS	0.09%	0.79%	0.00%	13.88%	0.01%
Comcast Corp	CMCSA	0.66%	2.12%	0.01%	15.40%	0.10%
Molson Coors Brewing Co	TAP	0.05%	2.45%	0.00%	5.24%	0.00%
KLA-Tencor Corp	KLAC	0.07%	2.55%	0.00%	7.37%	0.01%
Marriott International Inc/MD	MAR	0.18%	1.28%	0.00%	17.58%	0.03%

STANDARD AND POOR'S 500 INDEX

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McCormick & Co Inc/MD	MKC	0.06%	1.77%	0.00%	8.80%	0.01%
Nordstrom Inc	JWN	0.04%	2.82%	0.00%	8.45%	0.00%
PACCAR Inc	PCAR	0.09%	1.70%	0.00%	6.03%	0.01%
Costco Wholesale Corp	COST	0.39%	1.04%	0.00%	11.51%	0.04%
Stryker Corp	SYK	0.25%	1.15%	0.00%	8.70%	0.02%
Tyson Foods Inc	TSN	0.07%	2.08%	0.00%	5.80%	0.00%
Applied Materials Inc	AMAT	0.20%	1.65%	0.00%	14.46%	0.03%
American Airlines Group Inc	AAL	0.07%	1.01%	0.00%	16.07%	0.01%
Cardinal Health Inc	CAH	0.06%	3.81%	0.00%	7.79%	0.00%
Celgene Corp	CELG	0.26%	n/a	n/a	19.22%	0.05%
Cerner Corp	CERN	0.08%	n/a	n/a	11.68%	0.01%
Cincinnati Financial Corp	CINF	0.05%	2.80%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.07%	1.14%	0.00%	20.70%	0.01%
Flowserve Corp	FLS	0.02%	1.71%	0.00%	18.96%	0.00%
Electronic Arts Inc	EA	0.16%	n/a	n/a	13.65%	0.02%
Express Scripts Holding Co	ESRX	0.18%	n/a	n/a	6.52%	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.18%	0.00%	10.83%	0.01%
Fastenal Co	FAST	0.07%	2.81%	0.00%	13.85%	0.01%
M&T Bank Corp	MTB	0.10%	1.85%	0.00%	14.30%	0.01%
Xcel Energy Inc	XEL	0.10%	3.24%	0.00%	5.95%	0.01%
Fiserv Inc	FISV	0.12%	n/a	n/a	11.00%	0.01%
Fifth Third Bancorp	FITB	0.08%	2.43%	0.00%	5.65%	0.00%
Gilead Sciences Inc	GILD	0.41%	2.93%	0.01%	5.60%	0.02%
Hasbro Inc	HAS	0.05%	2.53%	0.00%	8.13%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.07%	3.63%	0.00%	13.36%	0.01%
Welltower Inc	WELL	0.09%	5.56%	0.01%	5.93%	0.01%
Biogen Inc	BIIB	0.27%	n/a	n/a	4.55%	0.01%
Northern Trust Corp	NTRS	0.10%	2.01%	0.00%	14.85%	0.01%
Packaging Corp of America	PKG	0.04%	2.80%	0.00%	10.00%	0.00%
Paychex Inc	PAYX	0.10%	3.25%	0.00%	9.00%	0.01%
People's United Financial Inc	PBCT	0.03%	3.84%	0.00%	2.00%	0.00%
QUALCOMM Inc	QCOM	0.38%	3.87%	0.01%	9.71%	0.04%
Roper Technologies Inc	ROP	0.13%	0.55%	0.00%	13.40%	0.02%
Ross Stores Inc	ROST	0.13%	1.03%	0.00%	10.27%	0.01%
IDEXX Laboratories Inc	IDXX	0.09%	n/a	n/a	18.89%	0.02%
Starbucks Corp	SBUX	0.29%	2.75%	0.01%	14.30%	0.04%
KeyCorp	KEY	0.09%	3.26%	0.00%	16.21%	0.01%
State Street Corp	STT	0.14%	2.13%	0.00%	15.83%	0.02%
Norwegian Cruise Line Holdings Ltd	NCLH	0.05%	n/a	n/a	20.17%	0.01%
US Bancorp	USB	0.35%	2.26%	0.01%	7.97%	0.03%
AO Smith Corp	AOS	0.03%	1.21%	0.00%	11.50%	0.00%
Symantec Corp	SYMC	0.05%	1.48%	0.00%	8.52%	0.00%
T Rowe Price Group Inc	TROW	0.12%	2.35%	0.00%	12.08%	0.01%
Waste Management Inc	WM	0.16%	2.07%	0.00%	11.61%	0.02%
CBS Corp	CBS	0.07%	1.37%	0.00%	15.39%	0.01%
Allergan PLC	AGN	0.25%	1.56%	0.00%	7.32%	0.02%
Constellation Brands Inc	STZ	0.14%	1.41%	0.00%	11.39%	0.02%
Xilinx Inc	XLNX	0.07%	2.00%	0.00%	11.60%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.04%	0.73%	0.00%	8.95%	0.00%
Zions Bancorporation	ZION	0.04%	2.32%	0.00%	10.30%	0.00%
Alaska Air Group Inc	ALK	0.03%	2.04%	0.00%	7.51%	0.00%
Invesco Ltd	IVZ	0.04%	4.45%	0.00%	7.48%	0.00%
Intuit Inc	INTU	0.21%	0.76%	0.00%	16.29%	0.03%
Morgan Stanley	MS	0.36%	2.37%	0.01%	13.44%	0.05%
Microchip Technology Inc	MCHP	0.09%	1.56%	0.00%	11.79%	0.01%
Chubb Ltd	CB	0.26%	2.09%	0.01%	10.00%	0.03%
Hologic Inc	HOLX	0.05%	n/a	n/a	9.51%	0.00%
Citizens Financial Group Inc	CFG	0.08%	2.71%	0.00%	21.50%	0.02%
O'Reilly Automotive Inc	ORLY	0.10%	n/a	n/a	14.81%	0.01%
Allstate Corp/The	ALL	0.14%	1.93%	0.00%	9.00%	0.01%
FLIR Systems Inc	FLIR	0.03%	1.09%	0.00%	n/a	n/a
Equity Residential	EQR	0.10%	3.30%	0.00%	5.70%	0.01%
BorgWarner Inc	BWA	0.04%	1.48%	0.00%	5.89%	0.00%
Newfield Exploration Co	NFX	0.02%	n/a	n/a	13.77%	0.00%
Incyte Corp	INCY	0.06%	n/a	n/a	58.24%	0.03%
Simon Property Group Inc	SPG	0.23%	4.54%	0.01%	5.89%	0.01%
Eastman Chemical Co	EMN	0.06%	2.16%	0.00%	5.90%	0.00%
Twitter Inc	TWTR	0.10%	n/a	n/a	38.08%	0.04%
AvalonBay Communities Inc	AVB	0.10%	3.32%	0.00%	5.61%	0.01%
Prudential Financial Inc	PRU	0.17%	3.57%	0.01%	9.00%	0.02%
United Parcel Service Inc	UPS	0.34%	3.04%	0.01%	8.73%	0.03%
Apartment Investment & Management Co	AIV	0.03%	3.56%	0.00%	6.02%	0.00%
Walgreens Boots Alliance Inc	WBA	0.27%	2.60%	0.01%	10.64%	0.03%
McKesson Corp	MCK	0.10%	1.24%	0.00%	6.35%	0.01%
Lockheed Martin Corp	LMT	0.38%	2.45%	0.01%	21.21%	0.08%
AmerisourceBergen Corp	ABC	0.07%	1.86%	0.00%	9.78%	0.01%
Capital One Financial Corp	COF	0.18%	1.70%	0.00%	16.00%	0.03%
Waters Corp	WAT	0.06%	n/a	n/a	9.10%	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	13.99%	0.01%
Darden Restaurants Inc	DRI	0.05%	2.81%	0.00%	10.09%	0.01%
NetApp Inc	NTAP	0.08%	2.06%	0.00%	11.77%	0.01%
Citrix Systems Inc	CTXS	0.06%	1.27%	0.00%	11.00%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.02%	2.31%	0.00%	n/a	n/a
DXC Technology Co	DXC	0.10%	0.90%	0.00%	6.15%	0.01%
DaVita Inc	DVA	0.05%	n/a	n/a	17.00%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.08%	2.28%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.04%	6.69%	0.00%	10.10%	0.00%
Estee Lauder Cos Inc/The	EL	0.12%	1.13%	0.00%	19.57%	0.02%
Cadence Design Systems Inc	CDNS	0.05%	n/a	n/a	12.00%	0.01%
Stericycle Inc	SRCL	0.02%	n/a	n/a	10.30%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Universal Health Services Inc	UHS	0.04%	0.33%	0.00%	7.93%	0.00%
E*TRADE Financial Corp	ETFC	0.06%	n/a	n/a	28.39%	0.02%
Skyworks Solutions Inc	SWKS	0.07%	1.61%	0.00%	12.04%	0.01%
National Oilwell Varco Inc	NOV	0.08%	0.41%	0.00%	41.00%	0.03%
Quest Diagnostics Inc	DGX	0.06%	1.86%	0.00%	9.20%	0.01%
Activision Blizzard Inc	ATVI	0.23%	0.46%	0.00%	14.21%	0.03%
Rockwell Automation Inc	ROK	0.09%	1.96%	0.00%	12.34%	0.01%
Kraft Heinz Co/The	KHC	0.30%	4.15%	0.01%	6.58%	0.02%
American Tower Corp	AMT	0.26%	2.08%	0.01%	16.10%	0.04%
HollyFrontier Corp	HFC	0.05%	1.77%	0.00%	8.92%	0.00%
Regeneron Pharmaceuticals Inc	REGN	0.16%	n/a	n/a	14.90%	0.02%
Amazon.com Inc	AMZN	3.50%	n/a	n/a	46.09%	1.62%
Ralph Lauren Corp	RL	0.03%	1.85%	0.00%	5.52%	0.00%
Boston Properties Inc	BXP	0.08%	2.55%	0.00%	5.54%	0.00%
Amphenol Corp	APH	0.11%	0.98%	0.00%	10.98%	0.01%
Arconic Inc	ARNC	0.04%	1.11%	0.00%	16.00%	0.01%
Pioneer Natural Resources Co	PXD	0.13%	0.17%	0.00%	15.00%	0.02%
Valero Energy Corp	VLO	0.21%	2.70%	0.01%	17.57%	0.04%
Synopsys Inc	SNPS	0.05%	n/a	n/a	n/a	n/a
L3 Technologies Inc	LLL	0.07%	1.49%	0.00%	12.39%	0.01%
Western Union Co/The	WU	0.04%	3.77%	0.00%	3.54%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.00%	0.00%	9.58%	0.00%
Accenture PLC	ACN	0.41%	1.67%	0.01%	11.15%	0.05%
TransDigm Group Inc	TDG	0.08%	n/a	n/a	11.80%	0.01%
Yum! Brands Inc	YUM	0.10%	1.82%	0.00%	12.57%	0.01%
Prologis Inc	PLD	0.14%	2.93%	0.00%	6.26%	0.01%
FirstEnergy Corp	FE	0.07%	4.06%	0.00%	-0.33%	0.00%
VeriSign Inc	VRSN	0.07%	n/a	n/a	10.40%	0.01%
Quanta Services Inc	PWR	0.02%	n/a	n/a	n/a	n/a
Henry Schein Inc	HSIC	0.05%	n/a	n/a	8.36%	0.00%
Ameren Corp	AEE	0.06%	2.95%	0.00%	8.97%	0.01%
ANSYS Inc	ANSS	0.06%	n/a	n/a	13.05%	0.01%
NVIDIA Corp	NVDA	0.60%	0.25%	0.00%	10.40%	0.06%
Sealed Air Corp	SEE	0.03%	1.45%	0.00%	11.28%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.19%	0.98%	0.00%	15.03%	0.03%
SVB Financial Group	SIVB	0.07%	n/a	n/a	11.50%	0.01%
Intuitive Surgical Inc	ISRG	0.23%	n/a	n/a	14.02%	0.03%
Affiliated Managers Group Inc	AMG	0.04%	0.75%	0.00%	11.68%	0.00%
Aetna Inc	AET	0.25%	1.06%	0.00%	11.08%	0.03%
Take-Two Interactive Software Inc	TTWO	0.05%	n/a	n/a	13.15%	0.01%
Republic Services Inc	RSG	0.10%	2.07%	0.00%	11.92%	0.01%
eBay Inc	EBAY	0.13%	n/a	n/a	9.93%	0.01%
Goldman Sachs Group Inc/The	GS	0.36%	1.35%	0.00%	12.69%	0.05%
Sempra Energy	SRE	0.13%	3.10%	0.00%	16.34%	0.02%
SBA Communications Corp	SBAC	0.07%	n/a	n/a	27.15%	0.02%
Moody's Corp	MCO	0.13%	1.03%	0.00%	8.00%	0.01%
Booking Holdings Inc	BKNG	0.40%	n/a	n/a	14.12%	0.06%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	10.27%	0.00%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	11.71%	0.01%
Devon Energy Corp	DVN	0.09%	0.71%	0.00%	12.41%	0.01%
Alphabet Inc	GOOGL	1.48%	n/a	n/a	16.80%	0.25%
Red Hat Inc	RHT	0.10%	n/a	n/a	17.34%	0.02%
Netflix Inc	NFLX	0.59%	n/a	n/a	48.46%	0.29%
Allegion PLC	ALLE	0.03%	1.03%	0.00%	11.25%	0.00%
Agilent Technologies Inc	A	0.09%	0.90%	0.00%	-0.45%	0.00%
Anthem Inc	ANTM	0.27%	1.19%	0.00%	10.21%	0.03%
CME Group Inc	CME	0.22%	1.76%	0.00%	15.00%	0.03%
Juniper Networks Inc	JNPR	0.04%	2.73%	0.00%	9.40%	0.00%
BlackRock Inc	BLK	0.33%	2.49%	0.01%	10.67%	0.03%
DTE Energy Co	DTE	0.08%	3.25%	0.00%	6.03%	0.00%
Nasdaq Inc	NDAQ	0.06%	1.93%	0.00%	10.64%	0.01%
Philip Morris International Inc	PM	0.54%	5.28%	0.03%	10.41%	0.06%
salesforce.com Inc	CRM	0.41%	n/a	n/a	26.30%	0.11%
Huntington Ingalls Industries Inc	HII	0.04%	1.24%	0.00%	27.50%	0.01%
MetLife Inc	MET	0.19%	3.67%	0.01%	11.42%	0.02%
Under Armour Inc	UA	0.02%	n/a	n/a	36.02%	0.01%
Tapestry Inc	TPR	0.05%	2.87%	0.00%	10.53%	0.01%
Fluor Corp	FLR	0.03%	1.64%	0.00%	28.88%	0.01%
CSX Corp	CSX	0.25%	1.25%	0.00%	11.96%	0.03%
Edwards Lifesciences Corp	EW	0.12%	n/a	n/a	15.33%	0.02%
Ameriprise Financial Inc	AMP	0.09%	2.47%	0.00%	n/a	n/a
Rockwell Collins Inc	COL	0.09%	0.95%	0.00%	11.60%	0.01%
TechnipFMC PLC	FTI	0.06%	1.60%	0.00%	8.70%	0.01%
Zimmer Biomet Holdings Inc	ZBH	0.10%	0.76%	0.00%	3.64%	0.00%
CBRE Group Inc	CBRE	0.07%	n/a	n/a	10.75%	0.01%
Mastercard Inc	MA	0.82%	0.51%	0.00%	21.46%	0.18%
CarMax Inc	KMX	0.05%	n/a	n/a	13.11%	0.01%
Intercontinental Exchange Inc	ICE	0.17%	1.30%	0.00%	10.14%	0.02%
Fidelity National Information Services Inc	FIS	0.14%	1.24%	0.00%	4.40%	0.01%
Chipotle Mexican Grill Inc	CMG	0.05%	n/a	n/a	19.15%	0.01%
Wynn Resorts Ltd	WYNN	0.07%	1.80%	0.00%	18.70%	0.01%
Assurant Inc	AIZ	0.03%	2.03%	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.04%	0.38%	0.00%	18.59%	0.01%
Regions Financial Corp	RF	0.08%	3.01%	0.00%	16.09%	0.01%
Monster Beverage Corp	MNST	0.14%	n/a	n/a	16.30%	0.02%
Mosaic Co/The	MOS	0.05%	0.33%	0.00%	7.00%	0.00%
Expedia Group Inc	EXPE	0.07%	0.96%	0.00%	15.32%	0.01%
Evergy Inc	EVRG	0.06%	2.85%	0.00%	9.34%	0.01%
Discovery Inc	DISCA	0.02%	n/a	n/a	n/a	n/a
CF Industries Holdings Inc	CF	0.04%	2.70%	0.00%	11.75%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Viacom Inc	VIAB	0.04%	2.75%	0.00%	4.23%	0.00%
Alphabet Inc	GOOG	1.72%	n/a	n/a	16.80%	0.29%
Cooper Cos Inc/The	COO	0.05%	0.02%	0.00%	10.50%	0.01%
TE Connectivity Ltd	TEL	0.13%	1.88%	0.00%	8.99%	0.01%
Discover Financial Services	DFS	0.10%	2.24%	0.00%	9.18%	0.01%
TripAdvisor Inc	TRIP	0.03%	n/a	n/a	14.41%	0.00%
Visa Inc	V	0.98%	0.61%	0.01%	17.70%	0.17%
Mid-America Apartment Communities Inc	MAA	0.05%	3.66%	0.00%	7.00%	0.00%
Xylem Inc/NY	XYL	0.06%	1.10%	0.00%	8.60%	0.00%
Marathon Petroleum Corp	MPC	0.15%	2.28%	0.00%	6.87%	0.01%
Tractor Supply Co	TSCO	0.04%	1.59%	0.00%	13.54%	0.01%
ResMed Inc	RMD	0.06%	1.32%	0.00%	16.10%	0.01%
Mettler-Toledo International Inc	MTD	0.06%	n/a	n/a	11.95%	0.01%
Copart Inc	CPRT	0.05%	n/a	n/a	n/a	n/a
Albemarle Corp	ALB	0.04%	1.42%	0.00%	12.23%	0.01%
Essex Property Trust Inc	ESS	0.06%	3.09%	0.00%	6.65%	0.00%
GGP Inc	GGP	0.08%	4.13%	0.00%	1.10%	0.00%
Realty Income Corp	O	0.06%	4.73%	0.00%	4.39%	0.00%
Seagate Technology PLC	STX	0.06%	4.79%	0.00%	-2.44%	0.00%
WestRock Co	WRK	0.06%	2.97%	0.00%	8.00%	0.00%
IHS Markit Ltd	INFO	0.08%	n/a	n/a	11.27%	0.01%
Western Digital Corp	WDC	0.08%	2.85%	0.00%	3.89%	0.00%
PepsiCo Inc	PEP	0.66%	3.23%	0.02%	6.68%	0.04%
Nektar Therapeutics	NKTR	0.04%	n/a	n/a	n/a	n/a
Church & Dwight Co Inc	CHD	0.06%	1.56%	0.00%	10.28%	0.01%
Duke Realty Corp	DRE	0.04%	2.75%	0.00%	-3.50%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.19%	0.00%	4.40%	0.00%
MGM Resorts International	MGM	0.07%	1.53%	0.00%	7.72%	0.01%
Twenty-First Century Fox Inc	FOX	0.14%	0.81%	0.00%	9.95%	0.01%
Alliant Energy Corp	LNT	0.04%	3.12%	0.00%	5.92%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	0.80%	0.00%	13.46%	0.01%
Lam Research Corp	LRCX	0.12%	2.31%	0.00%	11.46%	0.01%
Mohawk Industries Inc	MHK	0.06%	n/a	n/a	7.86%	0.00%
Pentair PLC	PNR	0.03%	1.57%	0.00%	10.55%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.18%	n/a	n/a	60.22%	0.11%
Facebook Inc	FB	1.68%	n/a	n/a	20.85%	0.35%
United Rentals Inc	URI	0.05%	n/a	n/a	23.52%	0.01%
ABIOMED Inc	ABMD	0.06%	n/a	n/a	37.00%	0.02%
Alexandria Real Estate Equities Inc	ARE	0.05%	2.92%	0.00%	6.78%	0.00%
United Continental Holdings Inc	UAL	0.09%	n/a	n/a	16.42%	0.01%
Delta Air Lines Inc	DAL	0.15%	2.57%	0.00%	15.22%	0.02%
News Corp	NWS	0.01%	1.31%	0.00%	11.70%	0.00%
Centene Corp	CNC	0.11%	n/a	n/a	15.35%	0.02%
Regency Centers Corp	REG	0.04%	3.49%	0.00%	8.51%	0.00%
Macerich Co/The	MAC	0.03%	5.01%	0.00%	4.95%	0.00%
Martin Marietta Materials Inc	MLM	0.05%	0.88%	0.00%	14.24%	0.01%
Envision Healthcare Corp	EVHC	0.02%	n/a	n/a	14.96%	0.00%
PayPal Holdings Inc	PYPL	0.39%	n/a	n/a	18.56%	0.07%
Coty Inc	COTY	0.04%	3.73%	0.00%	15.00%	0.01%
DISH Network Corp	DISH	0.03%	n/a	n/a	-11.61%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.12%	n/a	n/a	17.05%	0.02%
Everest Re Group Ltd	RE	0.04%	2.38%	0.00%	10.00%	0.00%
News Corp	NWSA	0.02%	1.33%	0.00%	11.70%	0.00%
Global Payments Inc	GPN	0.07%	0.04%	0.00%	22.03%	0.02%
Crown Castle International Corp	CCI	0.19%	3.79%	0.01%	19.23%	0.04%
Aptiv PLC	APTV	0.10%	0.90%	0.00%	10.53%	0.01%
Advance Auto Parts Inc	AAP	0.04%	0.17%	0.00%	16.64%	0.01%
Michael Kors Holdings Ltd	KORS	0.04%	n/a	n/a	4.78%	0.00%
Align Technology Inc	ALGN	0.12%	n/a	n/a	30.36%	0.04%
Illumina Inc	ILMN	0.19%	n/a	n/a	18.65%	0.04%
Alliance Data Systems Corp	ADS	0.05%	1.01%	0.00%	11.93%	0.01%
LKQ Corp	LKQ	0.04%	n/a	n/a	13.15%	0.01%
Nielsen Holdings PLC	NLSN	0.03%	5.94%	0.00%	12.00%	0.00%
Garmin Ltd	GRMN	0.05%	3.39%	0.00%	5.90%	0.00%
Cimarex Energy Co	XEC	0.04%	0.65%	0.00%	71.65%	0.03%
Zoetis Inc	ZTS	0.17%	0.58%	0.00%	17.66%	0.03%
Equinix Inc	EQIX	0.14%	2.08%	0.00%	16.11%	0.02%
Digital Realty Trust Inc	DLR	0.10%	3.33%	0.00%	7.28%	0.01%
Discovery Inc	DISCK	0.04%	n/a	n/a	n/a	n/a

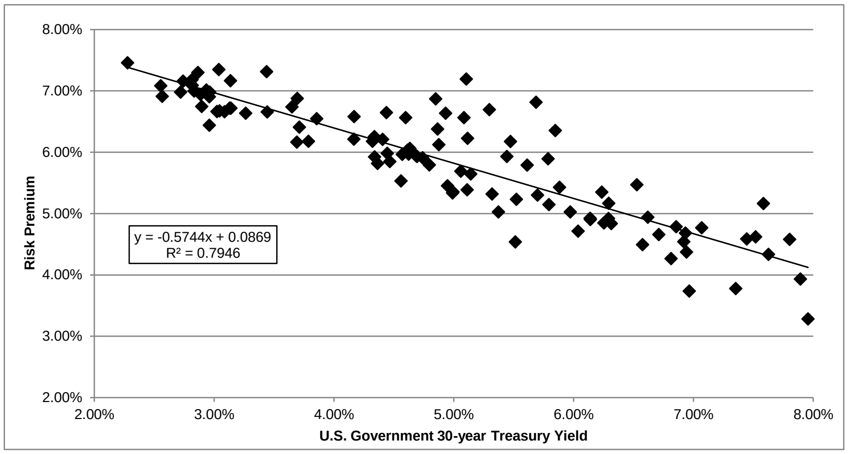
Notes:
[8] Equals sum of Col. [15]
[9] Equals sum of Col. [17]
[10] Equals ([8] x (1 + (0.5 x [9]))) + [9]
[11] Source: Schedule-11, at 1
[12] Equals [10] − [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional, as of July 31, 2018
[15] Equals [13] x [14]
[16] Source: Bloomberg Professional, as of July 31, 2018
[17] Equals [13] x [16]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
AVERAGE	10.79%	4.91%	5.87%
MEDIAN	10.67%	4.87%	5.97%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.89142
R Square	0.79462
Adjusted R Square	0.79265
Standard Error	0.00437
Observations	106

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0077	0.0077	402.3804	0.0000
Residual	104	0.0020	0.0000		
Total	105	0.0097			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0869	0.00147	59.13371	0.00000	0.08402	0.08985	0.08402	0.08985
U.S. Govt. 30-year Treasury	-0.5744	0.02864	-20.05942	0.00000	-0.63124	-0.51766	-0.63124	-0.51766

	[6]	[7]	[8]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Blue Chip Consensus Forecast (Q4 2018 - Q4 2019) [4]	3.56%	6.65%	10.21%
Blue Chip Consensus Forecast (2020-2024) [5]	4.20%	6.28%	10.48%
AVERAGE			10.34%

Notes:
[1] Source: Regulatory Research Associates, accessed August 27, 2018
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Blue Chip Financial Forecasts, Vol. 37, No. 8, August 1, 2018, at 2
[5] Source: Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, at 14
[6] See notes [4] & [5]
[7] Equals 0.0869 + (-0.5744 x Column [7])
[8] Equals Column [6] + Column [7]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
ALLETE, Inc.	ALE	3.97	1.89
Alliant Energy Corporation	LNT	9.83	2.29
Ameren Corporation	AEE	14.75	2.02
American Electric Power Company, Inc.	AEP	34.36	1.84
DTE Energy Company	DTE	1.91	1.94
Duke Energy Corporation	DUK	55.89	1.34
FirstEnergy Corporation	FE	17.00	2.28
NorthWestern Corporation	NWE	2.88	1.65
OGE Energy Corporation	OGE	7.06	1.82
Otter Tail Corporation	OTTR	1.91	2.68
PNM Resources, Inc.	PNM	3.07	1.79
PPL Corporation	PPL	19.92	1.77
Xcel Energy Inc.	XEL	23.26	2.00
Average		15.06	1.95
Median		9.83	1.89

Montana-Dakota Utilities Co. - MT Electric	
Common Equity ($ millions) [3]	106.8
Implied Market Capitalization [4]	201.8
As a percent of Proxy Group Median Market Capitalization	2.05%

Duff & Phelps 2017 Valuation Hand Book -- Size Premium

Breakdown of Deciles 1-10	[5] Market Capitalization of Largest Company ($ millions)	[6] Size Premium
1-Largest	609,163.498	-0.35%
2	24,233.747	0.61%
3	10,711.194	0.89%
4	5,676.716	0.98%
5	3,512.913	1.51%
6	2,390.899	1.66%
7	1,569.984	1.72%
8	1,030.426	2.08%
9	567.843	2.68%
10-Smallest	262.891	5.59%
Montana-Dakota Utilities Co. - MT Electric - Implied Market Capitalization	201.806	5.59%
Proxy Group Median Market Capitalization	9,832.576	0.89%
Size Premium [7]		4.70%

Notes:
[1] Source: Bloomberg Professional; equals 30-day average as of July 31, 2018
[2] Source: Bloomberg Professional; equals 30-day average as of July 31, 2018.
[3] Data provided by Montana-Dakota Utilities Co.
[4] Equals [3] x proxy group median market-to-book ratio
[5] Duff & Phelps 2017 Valuation Hand Book – U.S. Guide to Cost of Capital Exhibit 7.2.
[6] Duff & Phelps 2017 Valuation Hand Book – U.S. Guide to Cost of Capital Exhibit 4.7.
[7] Equals 5.59% − 0.89%

FLOTATION COST ADJUSTMENT -- INITIAL PROXY GROUP

Company	Date [i]	Shares Issued (000)	Offering Price	Under-writing Discount [ii]	Offering Expense ($000)	Net Proceeds Per Share	Total Flotation Costs ($000)	Equity Issue Before Costs ($000)	Net Proceeds ($000)	Flotation Cost Percentage
MDU Resources Group	2/4/2004	2,300	$ 23.32	$ 0.7930	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
MDU Resources Group	11/19/2002	2,400	$ 24.00	$ 0.7200	$ 193	$ 23.20	$ 1,921	$ 57,600	$ 55,680	3.33%
							$ 4,094	$ 111,236	$ 107,142	3.68%

Notes:
[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	ROE	ROE Adjusted for Flotation Costs
ALLETE, Inc.	ALE	$2.24	$77.44	2.89%	2.97%	3.09%	5.00%	6.00%	6.00%	5.67%	8.64%	8.75%
Alliant Energy Corporation	LNT	$1.34	$42.48	3.15%	3.25%	3.37%	6.50%	5.85%	5.60%	5.98%	9.23%	9.36%
Ameren Corporation	AEE	$1.83	$60.79	3.01%	3.11%	3.23%	7.50%	6.30%	6.50%	6.77%	9.88%	10.00%
American Electric Power Company, Inc.	AEP	$2.48	$69.75	3.56%	3.65%	3.79%	4.50%	5.59%	5.60%	5.23%	8.88%	9.02%
DTE Energy Company	DTE	$3.53	$105.08	3.36%	3.46%	3.59%	7.00%	5.67%	5.30%	5.99%	9.45%	9.58%
Duke Energy Corporation	DUK	$3.56	$79.72	4.47%	4.57%	4.75%	5.50%	4.01%	4.60%	4.70%	9.27%	9.45%
FirstEnergy Corporation	FE	$1.44	$35.62	4.04%	4.13%	4.29%	3.00%	Negative	6.00%	4.50%	8.63%	8.79%
NorthWestern Corporation	NWE	$2.20	$57.94	3.80%	3.85%	4.00%	3.50%	2.45%	2.30%	2.75%	6.60%	6.75%
OGE Energy Corporation	OGE	$1.33	$35.36	3.76%	3.86%	4.01%	6.00%	4.70%	4.80%	5.17%	9.03%	9.17%
Otter Tail Corporation	OTTR	$1.34	$48.24	2.78%	2.89%	3.00%	7.50%	9.00%	n/a	8.25%	11.14%	11.25%
PNM Resources, Inc.	PNM	$1.06	$38.51	2.75%	2.83%	2.94%	7.50%	5.15%	5.10%	5.92%	8.75%	8.86%
PPL Corporation	PPL	$1.64	$28.49	5.76%	5.85%	6.08%	2.00%	2.17%	6.00%	3.39%	9.24%	9.47%
Xcel Energy Inc.	XEL	$1.52	$45.71	3.33%	3.42%	3.55%	5.50%	5.96%	5.80%	5.75%	9.17%	9.30%
Mean											9.07%	9.21%
Flotation Cost Adjustment											[12]	0.14%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average ([11]) − Average ([10])

FLOTATION COST ADJUSTMENT -- REFINED PROXY GROUP

Company	Date [i]	Shares Issued (000)	Offering Price	Under-writing Discount [ii]	Offering Expense ($000)	Net Proceeds Per Share	Total Flotation Costs ($000)	Equity Issue Before Costs ($000)	Net Proceeds ($000)	Flotation Cost Percentage
MDU Resources Group	2/4/2004	2,300	$ 23.32	$ 0.7930	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
MDU Resources Group	11/19/2002	2,400	$ 24.00	$ 0.7200	$ 193	$ 23.20	$ 1,921	$ 57,600	$ 55,680	3.33%
							$ 4,094	$ 111,236	$ 107,142	3.68%

Notes:
[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	ROE	ROE Adjusted for Flotation Costs
ALLETE, Inc.	ALE	$2.24	$77.44	2.89%	2.97%	3.09%	5.00%	6.00%	6.00%	5.67%	8.64%	8.75%
Alliant Energy Corporation	LNT	$1.34	$42.48	3.15%	3.25%	3.37%	6.50%	5.85%	5.60%	5.98%	9.23%	9.36%
Ameren Corporation	AEE	$1.83	$60.79	3.01%	3.11%	3.23%	7.50%	6.30%	6.50%	6.77%	9.88%	10.00%
American Electric Power Company, Inc.	AEP	$2.48	$69.75	3.56%	3.65%	3.79%	4.50%	5.59%	5.60%	5.23%	8.88%	9.02%
DTE Energy Company	DTE	$3.53	$105.08	3.36%	3.46%	3.59%	7.00%	5.67%	5.30%	5.99%	9.45%	9.58%
FirstEnergy Corporation	FE	$1.44	$35.62	4.04%	4.13%	4.29%	3.00%	Negative	6.00%	4.50%	8.63%	8.79%
OGE Energy Corporation	OGE	$1.33	$35.36	3.76%	3.86%	4.01%	6.00%	4.70%	4.80%	5.17%	9.03%	9.17%
Otter Tail Corporation	OTTR	$1.34	$48.24	2.78%	2.89%	3.00%	7.50%	9.00%	n/a	8.25%	11.14%	11.25%
PPL Corporation	PPL	$1.64	$28.49	5.76%	5.85%	6.08%	2.00%	2.17%	6.00%	3.39%	9.24%	9.47%
Mean											9.35%	9.49%
Flotation Cost Adjustment											[12]	0.14%

Notes:
[1] Source: Bloomberg Professional.
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average ([11]) − Average ([10])

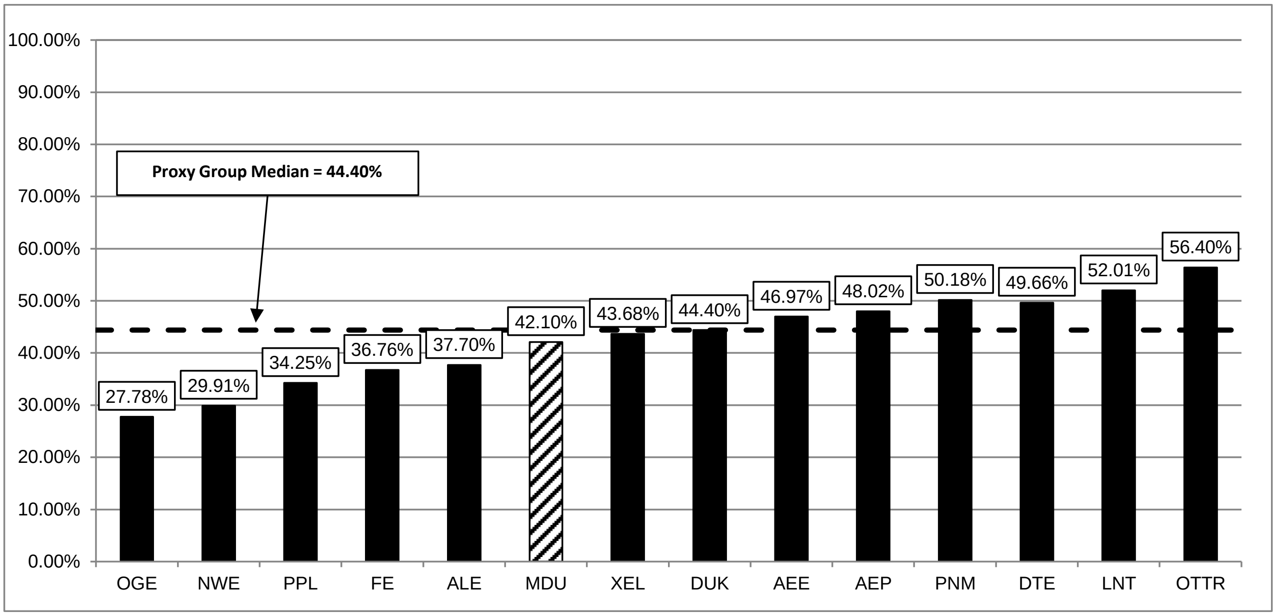
2019-2022 CAPITAL EXPENDITURES AS A PERCENT OF 2017 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]
		2017	2019	2020	2021	2022	2019-22 Cap. Ex. / 2017 Net Plant
ALLETE, Inc.	ALE						
Capital Spending per Share			$6.90	$6.83	$6.75	$6.75	
Common Shares Outstanding			52.00	$52.75	53.50	53.50	
Capital Expenditures			$358.8	$360.0	$361.1	$361.1	37.70%
Net Plant		$3,822.4					
Alliant Energy Corporation	LNT						
Capital Spending per Share			$7.10	$6.20	$5.30	$5.30	
Common Shares Outstanding			235.00	$235.00	235.00	235.00	
Capital Expenditures			$1,668.5	$1,457.0	$1,245.5	$1,245.5	52.01%
Net Plant		$10,797.9					
Ameren Corporation	AEE						
Capital Spending per Share			$11.25	$10.38	$9.50	$9.50	
Common Shares Outstanding			245.50	$247.75	250.00	250.00	
Capital Expenditures			$2,761.9	$2,570.4	$2,375.0	$2,375.0	46.97%
Net Plant		$21,466.0					
American Electric Power Company, Inc.	AEP						
Capital Spending per Share			$12.95	$12.10	$11.25	$11.25	
Common Shares Outstanding			495.00	$505.50	516.00	516.00	
Capital Expenditures			$6,410.3	$6,116.6	$5,805.0	$5,805.0	48.02%
Net Plant		$50,262.0					
DTE Energy Company	DTE						
Capital Spending per Share			$13.30	$13.28	$13.25	$13.25	
Common Shares Outstanding			192.00	$193.50	195.00	195.00	
Capital Expenditures			$2,553.6	$2,568.7	$2,583.8	$2,583.8	49.66%
Net Plant		$20,721.0					
Duke Energy Corporation	DUK						
Capital Spending per Share			$15.00	$13.38	$11.75	$11.75	
Common Shares Outstanding			731.50	$738.25	745.00	745.00	
Capital Expenditures			$10,972.5	$9,874.1	$8,753.8	$8,753.8	44.40%
Net Plant		$86,391.0					
FirstEnergy Corporation	FE						
Capital Spending per Share			$4.65	$4.83	$5.00	$5.00	
Common Shares Outstanding			540.00	$544.00	548.00	548.00	
Capital Expenditures			$2,511.0	$2,624.8	$2,740.0	$2,740.0	36.76%
Net Plant		$28,879.0					
NorthWestern Corporation	NWE						
Capital Spending per Share			$6.70	$6.48	$6.25	$6.25	
Common Shares Outstanding			50.40	$50.70	51.00	51.00	
Capital Expenditures			$337.7	$328.3	$318.8	$318.8	29.91%
Net Plant		$4,358.3					
OGE Energy Corporation	OGE						
Capital Spending per Share			$3.15	$2.95	$2.75	$2.75	
Common Shares Outstanding			199.70	$199.70	199.70	199.70	
Capital Expenditures			$629.1	$589.1	$549.2	$549.2	27.78%
Net Plant		$8,339.9					
Otter Tail Corporation	OTTR						
Capital Spending per Share			$9.65	$6.05	$2.45	$2.45	
Common Shares Outstanding			41.00	$42.50	44.00	44.00	
Capital Expenditures			$395.7	$257.1	$107.8	$107.8	56.40%
Net Plant		$1,539.6					
PNM Resources, Inc.	PNM						
Capital Spending per Share			$6.60	$7.43	$8.25	$8.25	
Common Shares Outstanding			79.65	$81.33	83.00	83.00	
Capital Expenditures			$525.7	$603.8	$684.8	$684.8	50.18%
Net Plant		$4,980.2					
PPL Corporation	PPL						
Capital Spending per Share			$4.35	$3.80	$3.25	$3.25	
Common Shares Outstanding			765.00	$772.50	780.00	780.00	
Capital Expenditures			$3,327.8	$2,935.5	$2,535.0	$2,535.0	34.25%
Net Plant		$33,092.0					
Xcel Energy Inc.	XEL						
Capital Spending per Share			$7.95	$7.35	$6.75	$6.75	
Common Shares Outstanding			518.00	$520.25	522.50	522.50	
Capital Expenditures			$4,118.1	$3,823.8	$3,526.9	$3,526.9	43.68%
Net Plant		$34,329.0					
Montana-Dakota Utilities Co.	MDU						
Capital Expenditures [7]			$29.8	$22.4	$20.2	$25.1	42.10%
Net Electric Plant in Service [8]		$231.51					

MDU CapEx Total (2019 - 2022)	$97.5
MDU CapEx Annual Average	$24.4
Proxy Group Median	44.4%
MDU as % Proxy Group Median	0.95

Notes:
[1] - [5] Value Line, May 18, June 15, and July 27, 2018
[6] Equals (Column [2] + [3] + [4] + [5]) / Column [1]
[7] - [8] Data provided by Montana-Dakota Utilities Co.

2019-2022 CAPITAL EXPENDITURES AS A PERCENT OF 2017 NET PLANT



Projected CAPEX / 2017 Net Plant

Company		2019-2022
OGE Energy Corporation	OGE	27.78%
NorthWestern Corporation	NWE	29.91%
PPL Corporation	PPL	34.25%
FirstEnergy Corporation	FE	36.76%
ALLETE, Inc.	ALE	37.70%
Montana-Dakota Utilities Co.	MDU	42.10%
Xcel Energy Inc.	XEL	43.68%
Duke Energy Corporation	DUK	44.40%
Ameren Corporation	AEE	46.97%
American Electric Power Company, Inc.	AEP	48.02%
PNM Resources, Inc.	PNM	50.18%
DTE Energy Company	DTE	49.66%
Alliant Energy Corporation	LNT	52.01%
Otter Tail Corporation	OTTR	56.40%
Proxy Group Median		44.40%
MDU/Proxy Group		0.95

Notes:
Source: Schedule-16 page 1 col. [6]

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

Company	Operation State		Test Year	Rate Base	Decoupling Full	Decoupling Partial	New Capital Generation Capacity	New Capital Generic Infrastructure
ALLETE, Inc.	Minnesota	1	Partially Forecast	Average				
Alliant Energy Corporation	Iowa	1	Historical	Average				
	Wisconsin	1	Fully Forecast	Average				
Ameren Corporation	Illinois	1	Historical	Year End				
	Missouri	1	Historical	Year End		x		x
American Electric Power Company, Inc.	Arkansas	1	Partially Forecast	Year End		x	x	
	Indiana	1	Historical	Year End		x		x
	Kentucky	1	Fully Forecast	Year End		x	x	
	Louisiana	1	Historical	Average		x		
	Michigan	1	Fully Forecast	Average				
	Ohio	1	Partially Forecast	Year End		x		x
	Oklahoma	1	Historical	Year End		x		x
	Tennessee	1	Fully Forecast	Average				
	Texas (PUC)	1	Historical	Year End				x
	Virginia	1	Fully Forecast	Year End			x	
	West Virginia	1	Historical	Average				x
DTE Energy Company	Michigan	1	Fully Forecast	Average				
Duke Energy Corporation	Florida	1	Fully Forecast	Average			x	
	Indiana	1	Historical	Year End		x	x	x
	Kentucky	1	Fully Forecast	Year End		x		
	North Carolina	1	Historical	Year End				
	Ohio	1	Partially Forecast	Year End		x		x
	South Carolina	1	Historical	Year End				
FirstEnergy Corp.	Maryland	1	Historical	Average				
	New Jersey	1	Partially Forecast	Year End				
	Ohio	1	Partially Forecast	Year End		x		x
	Pennsylvania	1	Fully Forecast	Year End				x
	West Virginia	1	Historical	Average				x
NorthWestern Corporation	Montana	1	Historical	Average				
	South Dakota	1	Historical	Average				
OGE Energy	Arkansas	1	Partially Forecast	Year End		x	x	x
	Oklahoma	1	Historical	Year End		x		x
Otter Tail Corporation	Minnesota	1	Partially Forecast	Average				
	North Dakota	1	Fully Forecast	Average				x
PNM Resources, Inc.	New Mexico	1	Historical	Year End				x
	Texas (PUC)	1	Historical	Year End				x
PPL Corporation	Kentucky	1	Fully Forecast	Year End		x		
	Pennsylvania	1	Fully Forecast	Year End				x
	Virginia	1	Fully Forecast	Year End				

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

Company	Operation State		Test Year	Rate Base	Decoupling Full	Decoupling Partial	New Capital Generation Capacity	New Capital Generic Infrastructure
Xcel Energy Inc.	Colorado	1	Historical	Average			x	x
	Minnesota	1	Partially Forecast	Average	x			
	New Mexico	1	Historical	Year End				
	North Dakota	1	Fully Forecast	Average				x
	South Dakota	1	Historical	Average		x	x	x
	Texas (PUC)	1	Historical	Year End				x
	Wisconsin	1	Fully Forecast	Average				
Proxy Companies			Historical: 22 Forecast: 24	Average: 20 Year End: 26	1	15	8	21
Total Jurisdictions	46							
Percent of Jurisdictions			Forecast: 52%	Year End: 57%	2%	33%	17%	46%
Montana-Dakota Utilities Co.	Montana		Historical	Average				

Notes:
[1] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 12, 2017. Operating subsidiaries not covered in this report were excluded from this exhibit.
[2] This exhibit only includes the adjustment mechanisms for the electric operating subsidiaries. Natural Gas subsidiaries were excluded from this exhibit.

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
	Operation State	Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Average / 2	5
	Wisconsin	Above Average / 2	8
Alliant Energy Corporation	Iowa	Average / 1	6
	Minnesota	Average / 2	5
	Wisconsin	Above Average / 2	8
Ameren Corporation	Illinois	Average / 2	5
	Missouri	Average / 3	4
American Electric Power Company, Inc.	Arkansas	Average / 1	6
	Indiana	Average / 1	6
	Kentucky	Average / 1	6
	Louisiana	Average / 2	5
	Michigan	Above Average / 3	7
	Ohio	Average / 2	5
	Oklahoma	Average / 3	4
	Tennessee	Above Average / 3	7
	Texas (PUC)	Average / 3	4
	Virginia	Above Average / 2	8
	West Virginia	Below Average / 2	2
DTE Energy Company	Michigan	Above Average / 3	7
Duke Energy Corporation	Florida	Above Average / 2	8
	Indiana	Average / 1	6
	Kentucky	Average / 1	6
	North Carolina	Average / 1	6
	Ohio	Average / 2	5
	South Carolina	Average / 3	4
	Tennessee	Above Average / 3	7
FirstEnergy Corporation	Maryland	Below Average / 3	1
	New Jersey	Below Average / 1	3
	New York	Average / 1	6
	Ohio	Average / 2	5
	Pennsylvania	Above Average / 3	7
	West Virginia	Below Average / 2	2
NorthWestern Corporation	Montana	Below Average / 1	3
	Nebraska	Average / 1	6
	South Dakota	Average / 2	5
	Wyoming	Average / 3	4
OGE Energy Corporation	Arkansas	Average / 1	6
	Oklahoma	Average / 3	4
Otter Tail Corporation	Minnesota	Average / 2	5
	North Dakota	Average / 1	6
	South Dakota	Average / 2	5
PNM Resources, Inc.	New Mexico	Below Average / 2	2
	Texas (PUC)	Average / 3	4
PPL Corporation	Kentucky	Average / 1	6
	Pennsylvania	Above Average / 3	7
	Tennessee	Above Average / 3	7
	Virginia	Above Average / 2	8
Xcel Energy Inc.	Colorado	Average / 2	5
	Michigan	Above Average / 3	7
	Minnesota	Average / 2	5
	New Mexico	Below Average / 2	2
	North Dakota	Average / 1	6
	South Dakota	Average / 2	5
	Texas (PUC)	Average / 3	4
	Wisconsin	Above Average / 2	8
Proxy Group Average		Average / 1 / Average / 2	5.35
Montana-Dakota Utilities Co.	Montana	Below Average / 1	3

Notes
[1] Source: State Regulatory Evaluations, Regulatory Research Associates, as of August 29, 2018
[2] AA/1= 9, AA/2= 8, AA/3= 7, A/1= 6, A/2= 5, A/3= 4, BA/1= 3, BA/2= 2, BA/3= 1

COMPARISON OF MONTANA-DAKOTA AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
	Operation State	Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Highly credit supportive	4
	Wisconsin	Most credit supportive	5
Alliant Energy Corporation	Iowa	Most credit supportive	5
	Minnesota	Highly credit supportive	4
	Wisconsin	Most credit supportive	5
Ameren Corporation	Illinois	Very credit supportive	3
	Missouri	Very credit supportive	3
American Electric Power Company, Inc.	Arkansas	Highly credit supportive	4
	Indiana	Highly credit supportive	4
	Kentucky	Most credit supportive	5
	Louisiana	Highly credit supportive	4
	Michigan	Most credit supportive	5
	Ohio	Very credit supportive	3
	Oklahoma	More credit supportive	2
	Tennessee	Highly credit supportive	4
	Texas (PUC)	Very credit supportive	3
	Virginia	Highly credit supportive	4
	West Virginia	Very credit supportive	3
DTE Energy Company	Michigan	Most credit supportive	5
Duke Energy Corporation	Florida	Most credit supportive	5
	Indiana	Highly credit supportive	4
	Kentucky	Most credit supportive	5
	North Carolina	Most credit supportive	5
	Ohio	Very credit supportive	3
	South Carolina	More credit supportive	2
	Tennessee	Highly credit supportive	4
FirstEnergy Corporation	Maryland	More credit supportive	2
	New Jersey	More credit supportive	2
	New York	Very credit supportive	3
	Ohio	Very credit supportive	3
	Pennsylvania	Highly credit supportive	4
	West Virginia	Very credit supportive	3
NorthWestern Corporation	Montana	More credit supportive	2
	Nebraska	Very credit supportive	3
	South Dakota	Very credit supportive	3
	Wyoming	Highly credit supportive	4
OGE Energy Corporation	Arkansas	Highly credit supportive	4
	Oklahoma	More credit supportive	2
Otter Tail Corporation	Minnesota	Highly credit supportive	4
	North Dakota	Highly credit supportive	4
	South Dakota	Very credit supportive	3
PNM Resources, Inc.	New Mexico	Credit supportive	1
	Texas (PUC)	Very credit supportive	3
PPL Corporation	Kentucky	Most credit supportive	5
	Pennsylvania	Highly credit supportive	4
	Tennessee	Highly credit supportive	4
	Virginia	Highly credit supportive	4
Xcel Energy Inc.	Colorado	Most credit supportive	5
	Michigan	Most credit supportive	5
	Minnesota	Highly credit supportive	4
	New Mexico	Credit supportive	1
	North Dakota	Highly credit supportive	4
	South Dakota	Very credit supportive	3
	Texas (PUC)	Very credit supportive	3
	Wisconsin	Most credit supportive	5
Proxy Group Average		Highly credit supportive / Very credit supportive	3.64
Montana-Dakota Utilities Co.	Montana	More credit supportive	2

Notes
[1] Source: U.S. And Canadian Regulatory Jurisdictions Support Utilities' Credit Quality--But Some More So Than Others, Standard and Poor's Ratings Service, dated June 25 2018
[2] Most= 5, Highly= 4, Very= 3, More= 2, Credit Supportive= 1

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Initial Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	60.43%	60.03%	59.64%	59.10%	58.70%	56.91%	56.99%	56.72%	58.56%
Alliant Energy Corporation	LNT	48.48%	48.57%	49.42%	48.65%	48.86%	49.05%	49.13%	49.50%	48.96%
Ameren Corporation	AEE	50.55%	51.65%	52.11%	51.51%	51.61%	51.74%	52.23%	51.15%	51.57%
American Electric Power Company, Inc.	AEP	46.83%	47.70%	47.44%	47.71%	47.92%	47.39%	47.75%	47.22%	47.49%
DTE Energy Company	DTE	49.27%	49.98%	49.23%	49.18%	49.67%	50.23%	50.12%	49.34%	49.63%
Duke Energy Corporation	DUK	52.32%	52.56%	52.61%	52.15%	52.16%	52.81%	53.12%	53.41%	52.64%
FirstEnergy Corporation	FE	55.81%	56.81%	55.99%	54.98%	53.65%	53.17%	53.67%	51.97%	54.51%
NorthWestern Corporation	NWE	47.48%	45.83%	45.40%	44.74%	45.64%	44.30%	44.83%	44.33%	45.32%
OGE Energy Corporation	OGE	53.59%	53.36%	53.05%	52.74%	53.46%	55.76%	56.23%	55.11%	54.16%
Otter Tail Corporation	OTTR	51.52%	51.37%	51.75%	52.26%	52.85%	52.77%	52.80%	52.53%	52.23%
PNM Resources, Inc.	PNM	48.11%	48.35%	49.44%	48.55%	48.69%	48.22%	48.58%	45.63%	48.20%
PPL Corporation	PPL	53.22%	53.79%	54.08%	56.35%	55.02%	55.73%	56.28%	56.58%	55.13%
Xcel Energy Inc.	XEL	54.03%	53.97%	53.45%	53.18%	54.26%	53.50%	53.48%	53.52%	53.67%
MEAN		51.66%	51.84%	51.82%	51.62%	51.73%	51.66%	51.94%	51.31%	51.70%
LOW		46.83%	45.83%	45.40%	44.74%	45.64%	44.30%	44.83%	44.33%	45.32%
HIGH		60.43%	60.03%	59.64%	59.10%	58.70%	56.91%	56.99%	56.72%	58.56%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	60.38%	60.04%	59.73%	59.16%	58.71%	56.92%	56.90%	56.63%	58.56%
Superior Water, Light and Power Company	ALE	62.68%	59.67%	55.83%	56.26%	58.21%	56.42%	60.80%	60.84%	58.84%
Interstate Power and Light Company	LNT	48.01%	48.37%	49.64%	48.78%	47.98%	48.09%	46.84%	48.15%	48.23%
Wisconsin Power and Light Company	LNT	49.09%	48.82%	49.13%	48.46%	50.03%	50.35%	52.11%	51.13%	49.89%
Ameren Illinois Company	AEE	51.85%	52.31%	52.77%	52.52%	52.87%	52.38%	53.09%	52.71%	52.56%
Union Electric Company	AEE	49.51%	51.12%	51.61%	50.75%	50.68%	51.27%	51.62%	50.07%	50.83%
AEP Texas, Inc.	AEP	44.66%	45.14%	42.81%	47.09%	47.27%	43.20%	43.76%	43.35%	44.66%
Appalachian Power Company	AEP	47.85%	47.59%	47.87%	47.09%	47.04%	46.41%	46.17%	45.53%	46.94%
Indiana Michigan Power Company	AEP	43.78%	44.37%	44.96%	45.85%	46.52%	46.81%	48.73%	48.38%	46.17%
Kentucky Power Company	AEP	43.85%	43.25%	42.88%	43.17%	43.23%	43.40%	43.20%	43.05%	43.25%
Kingsport Power Company	AEP	43.57%	46.53%	44.13%	45.30%	42.59%	43.66%	42.04%	47.68%	44.44%
Ohio Power Company	AEP	52.91%	57.36%	55.24%	53.98%	56.48%	56.51%	56.08%	52.30%	55.11%
Public Service Company of Oklahoma	AEP	44.86%	45.76%	46.66%	45.67%	45.23%	47.49%	48.52%	47.42%	46.45%
Southwestern Electric Power Company	AEP	46.24%	47.30%	48.15%	47.53%	46.62%	45.95%	46.12%	47.97%	46.98%
Wheeling Power Company	AEP	54.27%	54.26%	54.13%	54.10%	54.10%	54.12%	54.31%	54.08%	54.17%
DTE Electric Company	DTE	49.27%	49.98%	49.23%	49.18%	49.67%	50.23%	50.12%	49.34%	49.63%
Duke Energy Carolinas, LLC	DUK	51.60%	52.72%	52.78%	52.13%	52.45%	52.81%	53.59%	53.84%	52.74%
Duke Energy Florida, LLC	DUK	49.92%	49.25%	49.46%	47.74%	46.95%	49.31%	50.19%	51.10%	49.24%
Duke Energy Indiana, LLC	DUK	51.58%	50.91%	51.71%	51.89%	52.15%	51.59%	51.14%	49.35%	51.29%
Duke Energy Kentucky, Inc.	DUK	52.02%	53.11%	50.69%	54.11%	54.81%	53.42%	54.87%	54.14%	53.40%
Duke Energy Ohio, Inc.	DUK	64.73%	65.84%	65.79%	65.38%	65.36%	66.39%	65.96%	65.21%	65.58%
Duke Energy Progress, LLC	DUK	51.63%	51.46%	51.06%	51.24%	51.18%	51.58%	51.37%	52.85%	51.55%
Cleveland Electric Illuminating Company	FE	55.45%	55.23%	51.93%	52.02%	51.18%	50.85%	50.03%	45.70%	51.55%
Jersey Central Power & Light Company	FE	62.05%	65.30%	65.26%	62.73%	58.69%	58.02%	58.03%	56.56%	60.83%
Metropolitan Edison Company	FE	49.22%	52.33%	52.00%	50.54%	49.40%	48.99%	50.59%	49.12%	50.27%
Monongahela Power Company	FE	50.57%	49.15%	48.18%	46.60%	46.37%	45.47%	46.33%	44.67%	47.17%
Ohio Edison Company	FE	66.89%	64.91%	62.27%	62.80%	62.74%	63.66%	64.04%	64.25%	63.94%
Pennsylvania Electric Company	FE	51.43%	51.56%	53.29%	52.05%	51.61%	51.17%	49.24%	48.71%	51.13%
Pennsylvania Power Company	FE	52.23%	52.41%	55.74%	52.84%	52.09%	52.06%	51.43%	51.76%	52.57%
Potomac Edison Company	FE	52.64%	51.59%	51.27%	51.15%	50.74%	49.26%	51.31%	48.85%	50.85%
Toledo Edison Company	FE	59.04%	58.47%	55.49%	60.01%	61.00%	60.44%	60.07%	59.44%	59.24%
West Penn Power Company	FE	47.15%	52.82%	52.10%	50.33%	49.77%	48.84%	54.27%	51.43%	50.84%
NorthWestern Corporation	NWE	47.48%	45.83%	45.40%	44.74%	45.64%	44.30%	44.83%	44.33%	45.32%
Oklahoma Gas and Electric Company	OGE	53.59%	53.36%	53.05%	52.74%	53.46%	55.76%	56.23%	55.11%	54.16%
Otter Tail Power Company	OTTR	51.52%	51.37%	51.75%	52.26%	52.85%	52.77%	52.80%	52.53%	52.23%
Public Service Company of New Mexico	PNM	45.24%	45.31%	47.41%	46.15%	45.96%	44.94%	45.27%	42.90%	45.40%
Texas-New Mexico Power Company	PNM	56.03%	56.90%	55.45%	55.58%	56.81%	58.23%	58.67%	54.06%	56.46%
Kentucky Utilities Company	PPL	53.26%	53.53%	53.93%	58.21%	58.25%	58.50%	58.55%	58.36%	56.57%
Louisville Gas and Electric Company	PPL	52.66%	52.71%	53.42%	57.15%	57.10%	57.95%	57.90%	57.76%	55.83%
PPL Electric Utilities Corporation	PPL	53.50%	54.57%	54.54%	54.43%	51.04%	51.87%	53.20%	54.15%	53.41%
Northern States Power Company - MN	XEL	52.58%	51.85%	51.96%	51.90%	52.42%	51.87%	52.07%	51.85%	52.06%
Northern States Power Company - WI	XEL	53.09%	53.01%	52.35%	53.56%	54.46%	52.78%	54.74%	54.28%	53.53%
Public Service Company of Colorado	XEL	55.85%	56.46%	55.60%	54.84%	56.78%	55.51%	56.02%	55.65%	55.84%
Southwestern Public Service Company	XEL	53.41%	53.55%	52.29%	52.21%	52.86%	53.18%	50.45%	52.37%	52.54%

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Initial Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	39.45%	39.77%	40.12%	40.69%	41.17%	42.92%	42.98%	43.26%	41.29%
Alliant Energy Corporation	LNT	48.93%	48.88%	45.54%	46.41%	47.40%	47.77%	48.17%	47.24%	47.54%
Ameren Corporation	AEE	44.99%	46.61%	45.56%	45.86%	46.57%	46.83%	45.15%	45.86%	45.93%
American Electric Power Company, Inc.	AEP	49.65%	49.89%	50.65%	49.74%	48.86%	50.75%	51.43%	50.66%	50.20%
DTE Energy Company	DTE	47.12%	47.98%	48.26%	47.96%	48.69%	49.23%	49.87%	50.64%	48.72%
Duke Energy Corporation	DUK	46.61%	46.58%	46.62%	45.87%	46.41%	46.64%	46.77%	45.73%	46.41%
FirstEnergy Corporation	FE	41.18%	42.90%	43.24%	42.13%	43.31%	44.22%	44.36%	44.91%	43.28%
NorthWestern Corporation	NWE	52.52%	46.03%	47.51%	47.31%	48.24%	47.75%	49.12%	48.67%	48.39%
OGE Energy Corporation	OGE	46.41%	46.64%	46.95%	47.24%	46.54%	43.66%	43.77%	44.18%	45.67%
Otter Tail Corporation	OTTR	46.29%	38.21%	38.66%	42.23%	42.71%	43.08%	43.56%	44.47%	42.40%
PNM Resources, Inc.	PNM	49.80%	50.45%	50.29%	48.97%	49.95%	49.91%	50.11%	50.03%	49.94%
PPL Corporation	PPL	44.25%	44.73%	44.70%	42.15%	40.57%	41.36%	42.09%	42.52%	42.80%
Xcel Energy Inc.	XEL	45.28%	45.56%	45.97%	45.29%	44.85%	45.17%	46.26%	45.74%	45.52%
MEAN		46.35%	45.71%	45.70%	45.53%	45.79%	46.10%	46.43%	46.45%	46.01%
LOW		39.45%	38.21%	38.66%	40.69%	40.57%	41.36%	42.09%	42.52%	41.29%
HIGH		52.52%	50.45%	50.65%	49.74%	49.95%	50.75%	51.43%	50.66%	50.20%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	39.62%	39.96%	40.27%	40.84%	41.29%	43.08%	43.10%	43.37%	41.44%
Superior Water, Light and Power Company	ALE	32.58%	32.15%	33.74%	34.37%	35.91%	35.88%	37.83%	38.05%	35.06%
Interstate Power and Light Company	LNT	48.17%	47.78%	46.20%	47.07%	47.55%	47.64%	48.77%	47.12%	47.54%
Wisconsin Power and Light Company	LNT	49.94%	50.35%	44.65%	45.53%	47.20%	47.96%	47.38%	47.40%	47.55%
Ameren Illinois Company	AEE	43.74%	45.69%	43.21%	43.76%	44.88%	45.64%	42.02%	42.92%	43.98%
Union Electric Company	AEE	45.99%	47.35%	47.36%	47.45%	47.82%	47.70%	47.36%	47.91%	47.37%
AEP Texas, Inc.	AEP	50.86%	54.86%	57.19%	48.11%	49.56%	52.20%	53.84%	54.25%	52.61%
Appalachian Power Company	AEP	49.12%	50.09%	51.24%	51.31%	50.62%	52.56%	52.74%	52.58%	51.28%
Indiana Michigan Power Company	AEP	50.09%	51.40%	51.41%	53.24%	47.39%	48.51%	50.67%	51.36%	50.51%
Kentucky Power Company	AEP	54.91%	56.13%	56.33%	56.53%	55.98%	56.48%	56.06%	55.90%	56.04%
Kingsport Power Company	AEP	48.59%	53.47%	52.06%	44.26%	44.36%	23.26%	22.40%	26.43%	39.35%
Ohio Power Company	AEP	47.09%	40.46%	40.59%	41.20%	43.04%	43.49%	43.92%	43.02%	42.85%
Public Service Company of Oklahoma	AEP	48.42%	48.60%	48.87%	48.97%	48.60%	50.48%	51.48%	52.58%	49.75%
Southwestern Electric Power Company	AEP	50.67%	50.19%	50.81%	51.20%	49.83%	54.05%	53.88%	48.61%	51.16%
Wheeling Power Company	AEP	45.73%	45.74%	45.87%	45.90%	45.90%	45.88%	45.69%	45.92%	45.83%
DTE Electric Company	DTE	47.12%	47.98%	48.26%	47.96%	48.69%	49.23%	49.87%	50.64%	48.72%
Duke Energy Carolinas, LLC	DUK	48.20%	46.80%	45.00%	45.33%	45.92%	47.19%	46.41%	46.16%	46.38%
Duke Energy Florida, LLC	DUK	50.08%	50.75%	50.54%	52.26%	53.05%	47.70%	49.16%	44.53%	49.76%
Duke Energy Indiana, LLC	DUK	46.59%	47.10%	48.29%	48.11%	47.85%	48.41%	48.86%	50.65%	48.23%
Duke Energy Kentucky, Inc.	DUK	44.81%	46.89%	49.31%	42.97%	44.07%	44.18%	45.13%	45.86%	45.40%
Duke Energy Ohio, Inc.	DUK	33.26%	33.55%	34.21%	34.62%	34.64%	33.61%	34.04%	34.79%	34.09%
Duke Energy Progress, LLC	DUK	46.11%	46.99%	48.94%	44.52%	45.40%	48.42%	48.63%	46.58%	46.95%
Cleveland Electric Illuminating Company	FE	44.49%	44.70%	44.13%	43.81%	48.75%	49.08%	49.90%	50.57%	46.93%
Jersey Central Power & Light Company	FE	32.66%	34.70%	34.74%	34.12%	40.17%	39.96%	40.27%	40.15%	37.10%
Metropolitan Edison Company	FE	45.12%	47.67%	47.42%	46.71%	47.00%	48.40%	49.41%	49.65%	47.67%
Monongahela Power Company	FE	49.43%	50.85%	51.82%	51.30%	42.01%	47.05%	48.20%	47.77%	48.55%
Ohio Edison Company	FE	33.11%	35.09%	37.73%	37.20%	37.26%	36.34%	35.96%	35.75%	36.06%
Pennsylvania Electric Company	FE	45.45%	47.47%	46.71%	45.87%	46.60%	47.52%	50.76%	51.29%	47.71%
Pennsylvania Power Company	FE	41.55%	44.97%	44.26%	44.16%	45.49%	47.94%	48.57%	34.52%	43.93%
Potomac Edison Company	FE	47.36%	48.41%	48.73%	48.85%	49.26%	49.11%	46.16%	45.50%	47.92%
Toledo Edison Company	FE	38.39%	38.92%	40.50%	37.47%	36.55%	37.07%	37.42%	38.01%	38.04%
West Penn Power Company	FE	45.14%	47.18%	47.90%	41.73%	42.81%	43.97%	37.84%	47.71%	44.28%
NorthWestern Corporation	NWE	52.52%	46.03%	47.51%	47.31%	48.24%	47.75%	49.12%	48.67%	48.39%
Oklahoma Gas and Electric Company	OGE	46.41%	46.64%	46.95%	47.24%	46.54%	43.66%	43.77%	44.18%	45.67%
Otter Tail Power Company	OTTR	46.29%	38.21%	38.66%	42.23%	42.71%	43.08%	43.56%	44.47%	42.40%
Public Service Company of New Mexico	PNM	52.67%	53.05%	52.23%	52.27%	53.14%	52.73%	52.99%	52.68%	52.72%
Texas-New Mexico Power Company	PNM	41.90%	43.10%	44.55%	39.29%	40.47%	41.31%	41.33%	41.82%	41.72%
Kentucky Utilities Company	PPL	45.23%	45.60%	46.07%	40.90%	41.12%	41.22%	41.33%	41.13%	42.82%
Louisville Gas and Electric Company	PPL	44.04%	42.39%	41.49%	38.01%	38.06%	38.10%	39.08%	39.59%	40.10%
PPL Electric Utilities Corporation	PPL	43.70%	45.43%	45.46%	45.57%	41.67%	43.62%	44.76%	45.75%	44.50%
Northern States Power Company - MN	XEL	47.40%	47.14%	47.54%	46.44%	47.19%	47.29%	47.91%	48.14%	47.38%
Northern States Power Company - WI	XEL	45.60%	46.33%	41.87%	43.44%	43.39%	43.31%	44.99%	45.18%	44.26%
Public Service Company of Colorado	XEL	42.71%	43.47%	44.33%	45.09%	42.82%	43.05%	43.36%	43.85%	43.59%
Southwestern Public Service Company	XEL	46.34%	46.45%	47.71%	43.40%	44.17%	45.44%	49.55%	44.07%	45.89%

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Initial Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alliant Energy Corporation	LNT	2.18%	2.20%	2.32%	2.36%	2.44%	2.45%	2.47%	2.58%	2.38%
Ameren Corporation	AEE	0.98%	1.01%	1.03%	1.04%	1.05%	1.06%	1.06%	1.08%	1.04%
American Electric Power Company, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Corporation	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FirstEnergy Corporation	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OGE Energy Corporation	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Corporation	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PNM Resources, Inc.	PNM	0.27%	0.27%	0.27%	0.27%	0.28%	0.28%	0.28%	0.28%	0.28%
PPL Corporation	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Xcel Energy Inc.	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MEAN		0.26%	0.27%	0.28%	0.28%	0.29%	0.29%	0.29%	0.30%	0.28%
LOW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
HIGH		2.18%	2.20%	2.32%	2.36%	2.44%	2.45%	2.47%	2.58%	2.38%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Superior Water, Light and Power Company	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Interstate Power and Light Company	LNT	3.81%	3.85%	4.07%	4.15%	4.27%	4.28%	4.38%	4.73%	4.19%
Wisconsin Power and Light Company	LNT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ameren Illinois Company	AEE	0.95%	0.99%	1.03%	1.04%	1.07%	1.09%	1.11%	1.13%	1.05%
Union Electric Company	AEE	1.00%	1.03%	1.03%	1.03%	1.04%	1.03%	1.03%	1.04%	1.03%
AEP Texas, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Appalachian Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Indiana Michigan Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kingsport Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Oklahoma	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Electric Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wheeling Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Carolinas, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Florida, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Indiana, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Kentucky, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Ohio, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Progress, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cleveland Electric Illuminating Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jersey Central Power & Light Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Metropolitan Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monongahela Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Electric Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Potomac Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Toledo Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
West Penn Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oklahoma Gas and Electric Company	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Power Company	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of New Mexico	PNM	0.36%	0.37%	0.36%	0.37%	0.37%	0.37%	0.37%	0.37%	0.37%
Texas-New Mexico Power Company	PNM	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Utilities Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Louisville Gas and Electric Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PPL Electric Utilities Corporation	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Northern States Power Company - MN	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Northern States Power Company - WI	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Colorado	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Public Service Company	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Initial Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	0.11%	0.20%	0.24%	0.21%	0.13%	0.17%	0.03%	0.02%	0.14%
Alliant Energy Corporation	LNT	0.41%	0.35%	2.73%	2.59%	1.30%	0.72%	0.22%	0.67%	1.12%
Ameren Corporation	AEE	3.48%	0.72%	1.30%	1.59%	0.77%	0.37%	1.57%	1.91%	1.47%
American Electric Power Company, Inc.	AEP	3.51%	2.41%	1.92%	2.54%	3.22%	1.86%	0.83%	2.12%	2.30%
DTE Energy Company	DTE	3.61%	2.04%	2.51%	2.86%	1.64%	0.53%	0.01%	0.01%	1.65%
Duke Energy Corporation	DUK	1.07%	0.86%	0.77%	1.98%	1.43%	0.55%	0.11%	0.86%	0.95%
FirstEnergy Corporation	FE	3.02%	0.28%	0.77%	2.88%	3.04%	2.60%	1.97%	3.12%	2.21%
NorthWestern Corporation	NWE	0.00%	8.14%	7.09%	7.95%	6.11%	7.95%	6.04%	6.99%	6.29%
OGE Energy Corporation	OGE	0.00%	0.00%	0.00%	0.02%	0.00%	0.58%	0.00%	0.71%	0.16%
Otter Tail Corporation	OTTR	2.18%	10.42%	9.59%	5.50%	4.45%	4.15%	3.64%	3.00%	5.37%
PNM Resources, Inc.	PNM	1.82%	0.94%	0.00%	2.21%	1.08%	1.59%	1.03%	4.07%	1.59%
PPL Corporation	PPL	2.53%	1.48%	1.22%	1.49%	4.41%	2.91%	1.63%	0.91%	2.07%
Xcel Energy Inc.	XEL	0.69%	0.47%	0.58%	1.53%	0.88%	1.33%	0.26%	0.74%	0.81%
MEAN		1.73%	2.18%	2.21%	2.57%	2.19%	1.95%	1.33%	1.93%	2.01%
LOW		0.00%	0.00%	0.00%	0.02%	0.00%	0.17%	0.00%	0.01%	0.14%
HIGH		3.61%	10.42%	9.59%	7.95%	6.11%	7.95%	6.04%	6.99%	6.29%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Superior Water, Light and Power Company	ALE	4.74%	8.18%	10.43%	9.37%	5.88%	7.70%	1.38%	1.11%	6.10%
Interstate Power and Light Company	LNT	0.00%	0.00%	0.08%	0.00%	0.20%	0.00%	0.00%	0.00%	0.03%
Wisconsin Power and Light Company	LNT	0.96%	0.82%	6.22%	6.00%	2.77%	1.69%	0.51%	1.47%	2.56%
Ameren Illinois Company	AEE	3.46%	1.00%	3.00%	2.68%	1.18%	0.89%	3.79%	3.24%	2.40%
Union Electric Company	AEE	3.50%	0.50%	0.00%	0.77%	0.46%	0.00%	0.00%	0.98%	0.78%
AEP Texas, Inc.	AEP	4.49%	0.00%	0.00%	4.80%	3.16%	4.59%	2.40%	2.40%	2.73%
Appalachian Power Company	AEP	3.03%	2.33%	0.89%	1.59%	2.34%	1.03%	1.09%	1.89%	1.77%
Indiana Michigan Power Company	AEP	6.12%	4.23%	3.62%	0.92%	6.09%	4.68%	0.60%	0.26%	3.32%
Kentucky Power Company	AEP	1.25%	0.62%	0.79%	0.30%	0.78%	0.12%	0.73%	1.05%	0.70%
Kingsport Power Company	AEP	7.83%	0.00%	3.81%	10.45%	13.05%	33.08%	35.56%	25.90%	16.21%
Ohio Power Company	AEP	0.00%	2.18%	4.18%	4.82%	0.48%	0.00%	0.00%	4.68%	2.04%
Public Service Company of Oklahoma	AEP	6.72%	5.63%	4.47%	5.36%	6.16%	2.03%	0.00%	0.00%	3.80%
Southwestern Electric Power Company	AEP	3.09%	2.51%	1.04%	1.26%	3.55%	0.00%	0.00%	3.42%	1.86%
Wheeling Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	DTE	3.61%	2.04%	2.51%	2.86%	1.64%	0.53%	0.01%	0.01%	1.65%
Duke Energy Carolinas, LLC	DUK	0.20%	0.48%	2.21%	2.55%	1.63%	0.00%	0.00%	0.00%	0.88%
Duke Energy Florida, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	2.99%	0.65%	4.36%	1.00%
Duke Energy Indiana, LLC	DUK	1.83%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.48%
Duke Energy Kentucky, Inc.	DUK	3.18%	0.00%	0.00%	2.92%	1.13%	2.40%	0.00%	0.00%	1.20%
Duke Energy Ohio, Inc.	DUK	2.01%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.33%
Duke Energy Progress, LLC	DUK	2.25%	1.55%	0.00%	4.23%	3.42%	0.00%	0.00%	0.57%	1.50%
Cleveland Electric Illuminating Company	FE	0.06%	0.06%	3.94%	4.17%	0.06%	0.07%	0.07%	3.73%	1.52%
Jersey Central Power & Light Company	FE	5.30%	0.00%	0.00%	3.15%	1.14%	2.02%	1.70%	3.29%	2.08%
Metropolitan Edison Company	FE	5.66%	0.00%	0.58%	2.75%	3.61%	2.61%	0.00%	1.24%	2.05%
Monongahela Power Company	FE	0.00%	0.00%	0.00%	2.10%	11.62%	7.49%	5.47%	7.56%	4.28%
Ohio Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Electric Company	FE	3.12%	0.96%	0.00%	2.08%	1.79%	1.31%	0.00%	0.00%	1.16%
Pennsylvania Power Company	FE	6.22%	2.62%	0.00%	3.00%	2.42%	0.00%	0.00%	13.72%	3.50%
Potomac Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	1.63%	2.52%	5.65%	1.23%
Toledo Edison Company	FE	2.58%	2.61%	4.01%	2.52%	2.45%	2.49%	2.51%	2.55%	2.71%
West Penn Power Company	FE	7.72%	0.00%	0.00%	7.94%	7.41%	7.19%	7.89%	0.86%	4.88%
NorthWestern Corporation	NWE	0.00%	8.14%	7.09%	7.95%	6.11%	7.95%	6.04%	6.99%	6.29%
Oklahoma Gas and Electric Company	OGE	0.00%	0.00%	0.00%	0.02%	0.00%	0.58%	0.00%	0.71%	0.16%
Otter Tail Power Company	OTTR	2.18%	10.42%	9.59%	5.50%	4.45%	4.15%	3.64%	3.00%	5.37%
Public Service Company of New Mexico	PNM	1.73%	1.27%	0.00%	1.21%	0.52%	1.96%	1.37%	4.05%	1.51%
Texas-New Mexico Power Company	PNM	2.07%	0.00%	0.00%	5.13%	2.72%	0.45%	0.00%	4.12%	1.81%
Kentucky Utilities Company	PPL	1.51%	0.88%	0.00%	0.89%	0.63%	0.28%	0.12%	0.51%	0.60%
Louisville Gas and Electric Company	PPL	3.31%	4.90%	5.08%	4.84%	4.84%	3.95%	3.02%	2.65%	4.07%
PPL Electric Utilities Corporation	PPL	2.80%	0.00%	0.00%	0.00%	7.29%	4.51%	2.04%	0.10%	2.09%
Northern States Power Company - MN	XEL	0.01%	1.01%	0.49%	1.67%	0.39%	0.84%	0.01%	0.01%	0.55%
Northern States Power Company - WI	XEL	1.31%	0.67%	5.78%	3.00%	2.15%	3.90%	0.27%	0.54%	2.20%
Public Service Company of Colorado	XEL	1.44%	0.07%	0.07%	0.07%	0.40%	1.43%	0.62%	0.51%	0.58%
Southwestern Public Service Company	XEL	0.25%	0.00%	0.00%	4.39%	2.97%	1.38%	0.00%	3.55%	1.57%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Refined Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	60.43%	60.03%	59.64%	59.10%	58.70%	56.91%	56.99%	56.72%	58.56%
Alliant Energy Corporation	LNT	48.48%	48.57%	49.42%	48.65%	48.86%	49.05%	49.13%	49.50%	48.96%
Ameren Corporation	AEE	50.55%	51.65%	52.11%	51.51%	51.61%	51.74%	52.23%	51.15%	51.57%
American Electric Power Company, Inc.	AEP	46.83%	47.70%	47.44%	47.71%	47.92%	47.39%	47.75%	47.22%	47.49%
DTE Energy Company	DTE	49.27%	49.98%	49.23%	49.18%	49.67%	50.23%	50.12%	49.34%	49.63%
FirstEnergy Corporation	FE	55.81%	56.81%	55.99%	54.98%	53.65%	53.17%	53.67%	51.97%	54.51%
OGE Energy Corporation	OGE	53.59%	53.36%	53.05%	52.74%	53.46%	55.76%	56.23%	55.11%	54.16%
Otter Tail Corporation	OTTR	51.52%	51.37%	51.75%	52.26%	52.85%	52.77%	52.80%	52.53%	52.23%
PPL Corporation	PPL	53.22%	53.79%	54.08%	56.35%	55.02%	55.73%	56.28%	56.58%	55.13%
MEAN		52.19%	52.58%	52.52%	52.50%	52.42%	52.53%	52.80%	52.24%	52.47%
LOW		46.83%	47.70%	47.44%	47.71%	47.92%	47.39%	47.75%	47.22%	47.49%
HIGH		60.43%	60.03%	59.64%	59.10%	58.70%	56.91%	56.99%	56.72%	58.56%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	60.38%	60.04%	59.73%	59.16%	58.71%	56.92%	56.90%	56.63%	58.56%
Superior Water, Light and Power Company	ALE	62.68%	59.67%	55.83%	56.26%	58.21%	56.42%	60.80%	60.84%	58.84%
Interstate Power and Light Company	LNT	48.01%	48.37%	49.64%	48.78%	47.98%	48.09%	46.84%	48.15%	48.23%
Wisconsin Power and Light Company	LNT	49.09%	48.82%	49.13%	48.46%	50.03%	50.35%	52.11%	51.13%	49.89%
Ameren Illinois Company	AEE	51.85%	52.31%	52.77%	52.52%	52.87%	52.38%	53.09%	52.71%	52.56%
Union Electric Company	AEE	49.51%	51.12%	51.61%	50.75%	50.68%	51.27%	51.62%	50.07%	50.83%
AEP Texas, Inc.	AEP	44.66%	45.14%	42.81%	47.09%	47.27%	43.20%	43.76%	43.35%	44.66%
Appalachian Power Company	AEP	47.85%	47.59%	47.87%	47.09%	47.04%	46.41%	46.17%	45.53%	46.94%
Indiana Michigan Power Company	AEP	43.78%	44.37%	44.96%	45.85%	46.52%	46.81%	48.73%	48.38%	46.17%
Kentucky Power Company	AEP	43.85%	43.25%	42.88%	43.17%	43.23%	43.40%	43.20%	43.05%	43.25%
Kingsport Power Company	AEP	43.57%	46.53%	44.13%	45.30%	42.59%	43.66%	42.04%	47.68%	44.44%
Ohio Power Company	AEP	52.91%	57.36%	55.24%	53.98%	56.48%	56.51%	56.08%	52.30%	55.11%
Public Service Company of Oklahoma	AEP	44.86%	45.76%	46.66%	45.67%	45.23%	47.49%	48.52%	47.42%	46.45%
Southwestern Electric Power Company	AEP	46.24%	47.30%	48.15%	47.53%	46.62%	45.95%	46.12%	47.97%	46.98%
Wheeling Power Company	AEP	54.27%	54.26%	54.13%	54.10%	54.10%	54.12%	54.31%	54.08%	54.17%
DTE Electric Company	DTE	49.27%	49.98%	49.23%	49.18%	49.67%	50.23%	50.12%	49.34%	49.63%
Cleveland Electric Illuminating Company	FE	55.45%	55.23%	51.93%	52.02%	51.18%	50.85%	50.03%	45.70%	51.55%
Jersey Central Power & Light Company	FE	62.05%	65.30%	65.26%	62.73%	58.69%	58.02%	58.03%	56.56%	60.83%
Metropolitan Edison Company	FE	49.22%	52.33%	52.00%	50.54%	49.40%	48.99%	50.59%	49.12%	50.27%
Monongahela Power Company	FE	50.57%	49.15%	48.18%	46.60%	46.37%	45.47%	46.33%	44.67%	47.17%
Ohio Edison Company	FE	66.89%	64.91%	62.27%	62.80%	62.74%	63.66%	64.04%	64.25%	63.94%
Pennsylvania Electric Company	FE	51.43%	51.56%	53.29%	52.05%	51.61%	51.17%	49.24%	48.71%	51.13%
Pennsylvania Power Company	FE	52.23%	52.41%	55.74%	52.84%	52.09%	52.06%	51.43%	51.76%	52.57%
Potomac Edison Company	FE	52.64%	51.59%	51.27%	51.15%	50.74%	49.26%	51.31%	48.85%	50.85%
Toledo Edison Company	FE	59.04%	58.47%	55.49%	60.01%	61.00%	60.44%	60.07%	59.44%	59.24%
West Penn Power Company	FE	47.15%	52.82%	52.10%	50.33%	49.77%	48.84%	54.27%	51.43%	50.84%
Oklahoma Gas and Electric Company	OGE	53.59%	53.36%	53.05%	52.74%	53.46%	55.76%	56.23%	55.11%	54.16%
Otter Tail Power Company	OTTR	51.52%	51.37%	51.75%	52.26%	52.85%	52.77%	52.80%	52.53%	52.23%
Kentucky Utilities Company	PPL	53.26%	53.53%	53.93%	58.21%	58.25%	58.50%	58.55%	58.36%	56.57%
Louisville Gas and Electric Company	PPL	52.66%	52.71%	53.42%	57.15%	57.10%	57.95%	57.90%	57.76%	55.83%
PPL Electric Utilities Corporation	PPL	53.50%	54.57%	54.54%	54.43%	51.04%	51.87%	53.20%	54.15%	53.41%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Refined Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	39.45%	39.77%	40.12%	40.69%	41.17%	42.92%	42.98%	43.26%	41.29%
Alliant Energy Corporation	LNT	48.93%	48.88%	45.54%	46.41%	47.40%	47.77%	48.17%	47.24%	47.54%
Ameren Corporation	AEE	44.99%	46.61%	45.56%	45.86%	46.57%	46.83%	45.15%	45.86%	45.93%
American Electric Power Company, Inc.	AEP	49.65%	49.89%	50.65%	49.74%	48.86%	50.75%	51.43%	50.66%	50.20%
DTE Energy Company	DTE	47.12%	47.98%	48.26%	47.96%	48.69%	49.23%	49.87%	50.64%	48.72%
FirstEnergy Corporation	FE	41.18%	42.90%	43.24%	42.13%	43.31%	44.22%	44.36%	44.91%	43.28%
OGE Energy Corporation	OGE	46.41%	46.64%	46.95%	47.24%	46.54%	43.66%	43.77%	44.18%	45.67%
Otter Tail Corporation	OTTR	46.29%	38.21%	38.66%	42.23%	42.71%	43.08%	43.56%	44.47%	42.40%
PPL Corporation	PPL	44.25%	44.73%	44.70%	42.15%	40.57%	41.36%	42.09%	42.52%	42.80%
MEAN		45.36%	45.07%	44.85%	44.93%	45.09%	45.54%	45.71%	45.97%	45.32%
LOW		39.45%	38.21%	38.66%	40.69%	40.57%	41.36%	42.09%	42.52%	41.29%
HIGH		49.65%	49.89%	50.65%	49.74%	48.86%	50.75%	51.43%	50.66%	50.20%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	39.62%	39.96%	40.27%	40.84%	41.29%	43.08%	43.10%	43.37%	41.44%
Superior Water, Light and Power Company	ALE	32.58%	32.15%	33.74%	34.37%	35.91%	35.88%	37.83%	38.05%	35.06%
Interstate Power and Light Company	LNT	48.17%	47.78%	46.20%	47.07%	47.55%	47.64%	48.77%	47.12%	47.54%
Wisconsin Power and Light Company	LNT	49.94%	50.35%	44.65%	45.53%	47.20%	47.96%	47.38%	47.40%	47.55%
Ameren Illinois Company	AEE	43.74%	45.69%	43.21%	43.76%	44.88%	45.64%	42.02%	42.92%	43.98%
Union Electric Company	AEE	45.99%	47.35%	47.36%	47.45%	47.82%	47.70%	47.36%	47.91%	47.37%
AEP Texas, Inc.	AEP	50.86%	54.86%	57.19%	48.11%	49.56%	52.20%	53.84%	54.25%	52.61%
Appalachian Power Company	AEP	49.12%	50.09%	51.24%	51.31%	50.62%	52.56%	52.74%	52.58%	51.28%
Indiana Michigan Power Company	AEP	50.09%	51.40%	51.41%	53.24%	47.39%	48.51%	50.67%	51.36%	50.51%
Kentucky Power Company	AEP	54.91%	56.13%	56.33%	56.53%	55.98%	56.48%	56.06%	55.90%	56.04%
Kingsport Power Company	AEP	48.59%	53.47%	52.06%	44.26%	44.36%	23.26%	22.40%	26.43%	39.35%
Ohio Power Company	AEP	47.09%	40.46%	40.59%	41.20%	43.04%	43.49%	43.92%	43.02%	42.85%
Public Service Company of Oklahoma	AEP	48.42%	48.60%	48.87%	48.97%	48.60%	50.48%	51.48%	52.58%	49.75%
Southwestern Electric Power Company	AEP	50.67%	50.19%	50.81%	51.20%	49.83%	54.05%	53.88%	48.61%	51.16%
Wheeling Power Company	AEP	45.73%	45.74%	45.87%	45.90%	45.90%	45.88%	45.69%	45.92%	45.83%
DTE Electric Company	DTE	47.12%	47.98%	48.26%	47.96%	48.69%	49.23%	49.87%	50.64%	48.72%
Cleveland Electric Illuminating Company	FE	44.49%	44.70%	44.13%	43.81%	48.75%	49.08%	49.90%	50.57%	46.93%
Jersey Central Power & Light Company	FE	32.66%	34.70%	34.74%	34.12%	40.17%	39.96%	40.27%	40.15%	37.10%
Metropolitan Edison Company	FE	45.12%	47.67%	47.42%	46.71%	47.00%	48.40%	49.41%	49.65%	47.67%
Monongahela Power Company	FE	49.43%	50.85%	51.82%	51.30%	42.01%	47.05%	48.20%	47.77%	48.55%
Ohio Edison Company	FE	33.11%	35.09%	37.73%	37.20%	37.26%	36.34%	35.96%	35.75%	36.06%
Pennsylvania Electric Company	FE	45.45%	47.47%	46.71%	45.87%	46.60%	47.52%	50.76%	51.29%	47.71%
Pennsylvania Power Company	FE	41.55%	44.97%	44.26%	44.16%	45.49%	47.94%	48.57%	34.52%	43.93%
Potomac Edison Company	FE	47.36%	48.41%	48.73%	48.85%	49.26%	49.11%	46.16%	45.50%	47.92%
Toledo Edison Company	FE	38.39%	38.92%	40.50%	37.47%	36.55%	37.07%	37.42%	38.01%	38.04%
West Penn Power Company	FE	45.14%	47.18%	47.90%	41.73%	42.81%	43.97%	37.84%	47.71%	44.28%
Oklahoma Gas and Electric Company	OGE	46.41%	46.64%	46.95%	47.24%	46.54%	43.66%	43.77%	44.18%	45.67%
Otter Tail Power Company	OTTR	46.29%	38.21%	38.66%	42.23%	42.71%	43.08%	43.56%	44.47%	42.40%
Kentucky Utilities Company	PPL	45.23%	45.60%	46.07%	40.90%	41.12%	41.22%	41.33%	41.13%	42.82%
Louisville Gas and Electric Company	PPL	44.04%	42.39%	41.49%	38.01%	38.06%	38.10%	39.08%	39.59%	40.10%
PPL Electric Utilities Corporation	PPL	43.70%	45.43%	45.46%	45.57%	41.67%	43.62%	44.76%	45.75%	44.50%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Refined Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alliant Energy Corporation	LNT	2.18%	2.20%	2.32%	2.36%	2.44%	2.45%	2.47%	2.58%	2.38%
Ameren Corporation	AEE	0.98%	1.01%	1.03%	1.04%	1.05%	1.06%	1.06%	1.08%	1.04%
American Electric Power Company, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FirstEnergy Corporation	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OGE Energy Corporation	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Corporation	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PPL Corporation	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MEAN		0.35%	0.36%	0.37%	0.38%	0.39%	0.39%	0.39%	0.41%	0.38%
LOW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
HIGH		2.18%	2.20%	2.32%	2.36%	2.44%	2.45%	2.47%	2.58%	2.38%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Superior Water, Light and Power Company	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Interstate Power and Light Company	LNT	3.81%	3.85%	4.07%	4.15%	4.27%	4.28%	4.38%	4.73%	4.19%
Wisconsin Power and Light Company	LNT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ameren Illinois Company	AEE	0.95%	0.99%	1.03%	1.04%	1.07%	1.09%	1.11%	1.13%	1.05%
Union Electric Company	AEE	1.00%	1.03%	1.03%	1.03%	1.04%	1.03%	1.03%	1.04%	1.03%
AEP Texas, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Appalachian Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Indiana Michigan Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kingsport Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Oklahoma	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Electric Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wheeling Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cleveland Electric Illuminating Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Jersey Central Power & Light Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Metropolitan Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Monongahela Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Electric Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Potomac Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Toledo Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
West Penn Power Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oklahoma Gas and Electric Company	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Power Company	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Utilities Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Louisville Gas and Electric Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PPL Electric Utilities Corporation	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Refined Proxy Group Company	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE, Inc.	ALE	0.11%	0.20%	0.24%	0.21%	0.13%	0.17%	0.03%	0.02%	0.14%
Alliant Energy Corporation	LNT	0.41%	0.35%	2.73%	2.59%	1.30%	0.72%	0.22%	0.67%	1.12%
Ameren Corporation	AEE	3.48%	0.72%	1.30%	1.59%	0.77%	0.37%	1.57%	1.91%	1.47%
American Electric Power Company, Inc.	AEP	3.51%	2.41%	1.92%	2.54%	3.22%	1.86%	0.83%	2.12%	2.30%
DTE Energy Company	DTE	3.61%	2.04%	2.51%	2.86%	1.64%	0.53%	0.01%	0.01%	1.65%
FirstEnergy Corporation	FE	3.02%	0.28%	0.77%	2.88%	3.04%	2.60%	1.97%	3.12%	2.21%
OGE Energy Corporation	OGE	0.00%	0.00%	0.00%	0.02%	0.00%	0.58%	0.00%	0.71%	0.16%
Otter Tail Corporation	OTTR	2.18%	10.42%	9.59%	5.50%	4.45%	4.15%	3.64%	3.00%	5.37%
PPL Corporation	PPL	2.53%	1.48%	1.22%	1.49%	4.41%	2.91%	1.63%	0.91%	2.07%
MEAN		2.10%	1.99%	2.25%	2.19%	2.11%	1.54%	1.10%	1.39%	1.83%
LOW		0.00%	0.00%	0.00%	0.02%	0.00%	0.17%	0.00%	0.01%	0.14%
HIGH		3.61%	10.42%	9.59%	5.50%	4.45%	4.15%	3.64%	3.12%	5.37%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	Average
ALLETE (Minnesota Power)	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Superior Water, Light and Power Company	ALE	4.74%	8.18%	10.43%	9.37%	5.88%	7.70%	1.38%	1.11%	6.10%
Interstate Power and Light Company	LNT	0.00%	0.00%	0.08%	0.00%	0.20%	0.00%	0.00%	0.00%	0.03%
Wisconsin Power and Light Company	LNT	0.96%	0.82%	6.22%	6.00%	2.77%	1.69%	0.51%	1.47%	2.56%
Ameren Illinois Company	AEE	3.46%	1.00%	3.00%	2.68%	1.18%	0.89%	3.79%	3.24%	2.40%
Union Electric Company	AEE	3.50%	0.50%	0.00%	0.77%	0.46%	0.00%	0.00%	0.98%	0.78%
AEP Texas, Inc.	AEP	4.49%	0.00%	0.00%	4.80%	3.16%	4.59%	2.40%	2.40%	2.73%
Appalachian Power Company	AEP	3.03%	2.33%	0.89%	1.59%	2.34%	1.03%	1.09%	1.89%	1.77%
Indiana Michigan Power Company	AEP	6.12%	4.23%	3.62%	0.92%	6.09%	4.68%	0.60%	0.26%	3.32%
Kentucky Power Company	AEP	1.25%	0.62%	0.79%	0.30%	0.78%	0.12%	0.73%	1.05%	0.70%
Kingsport Power Company	AEP	7.83%	0.00%	3.81%	10.45%	13.05%	33.08%	35.56%	25.90%	16.21%
Ohio Power Company	AEP	0.00%	2.18%	4.18%	4.82%	0.48%	0.00%	0.00%	4.68%	2.04%
Public Service Company of Oklahoma	AEP	6.72%	5.63%	4.47%	5.36%	6.16%	2.03%	0.00%	0.00%	3.80%
Southwestern Electric Power Company	AEP	3.09%	2.51%	1.04%	1.26%	3.55%	0.00%	0.00%	3.42%	1.86%
Wheeling Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	DTE	3.61%	2.04%	2.51%	2.86%	1.64%	0.53%	0.01%	0.01%	1.65%
Cleveland Electric Illuminating Company	FE	0.06%	0.06%	3.94%	4.17%	0.06%	0.07%	0.07%	3.73%	1.52%
Jersey Central Power & Light Company	FE	5.30%	0.00%	0.00%	3.15%	1.14%	2.02%	1.70%	3.29%	2.08%
Metropolitan Edison Company	FE	5.66%	0.00%	0.58%	2.75%	3.61%	2.61%	0.00%	1.24%	2.05%
Monongahela Power Company	FE	0.00%	0.00%	0.00%	2.10%	11.62%	7.49%	5.47%	7.56%	4.28%
Ohio Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania Electric Company	FE	3.12%	0.96%	0.00%	2.08%	1.79%	1.31%	0.00%	0.00%	1.16%
Pennsylvania Power Company	FE	6.22%	2.62%	0.00%	3.00%	2.42%	0.00%	0.00%	13.72%	3.50%
Potomac Edison Company	FE	0.00%	0.00%	0.00%	0.00%	0.00%	1.63%	2.52%	5.65%	1.23%
Toledo Edison Company	FE	2.58%	2.61%	4.01%	2.52%	2.45%	2.49%	2.51%	2.55%	2.71%
West Penn Power Company	FE	7.72%	0.00%	0.00%	7.94%	7.41%	7.19%	7.89%	0.86%	4.88%
Oklahoma Gas and Electric Company	OGE	0.00%	0.00%	0.00%	0.02%	0.00%	0.58%	0.00%	0.71%	0.16%
Otter Tail Power Company	OTTR	2.18%	10.42%	9.59%	5.50%	4.45%	4.15%	3.64%	3.00%	5.37%
Kentucky Utilities Company	PPL	1.51%	0.88%	0.00%	0.89%	0.63%	0.28%	0.12%	0.51%	0.60%
Louisville Gas and Electric Company	PPL	3.31%	4.90%	5.08%	4.84%	4.84%	3.95%	3.02%	2.65%	4.07%
PPL Electric Utilities Corporation	PPL	2.80%	0.00%	0.00%	0.00%	7.29%	4.51%	2.04%	0.10%	2.09%

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

D2018.9.__

PREPARED DIRECT TESTIMONY OF

LARRY E. KENNEDY

Q1. Please state your name and business address.

A1. My name is Larry E Kennedy. My business address is 200 Rivercrest Drive SE, Suite 277, Calgary, Alberta, T2C 2X5.

Q2. By whom are you employed?

A2. I am employed by Concentric Energy Advisors., Inc.

Q3. What is your position with Concentric Energy Advisors, Inc. ("Concentric")?

A3. I am employed by Concentric as a Vice President.

Q4. On whose behalf are you submitting this Direct Testimony?

A4. I am submitting this Direct Testimony before the Montana Public Service Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q5. Please describe your education and experience.

A5. I am a Certified Depreciation Professional, with nearly 40 years of regulatory plant accounting and depreciation experience, and 20 years of depreciation and plant accounting consulting to the regulated utility industry. I have advised numerous energy and utility clients on a wide range of accounting, property tax and utility depreciation matters. Many of these assignments have included the determination of the cost of appropriate annual depreciation accrual rates. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No.__(LEK-2), Schedule 1.

Q6. Please describe Concentric's activities in energy and utility engagements.

A6. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q7. Have you testified before any regulatory authorities?

A7. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No.__(LEK-2), Schedule 1.

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q8. What is the purpose of your Direct Testimony?

A8. The purpose of my Direct Testimony is to set forth the results of my full and comprehensive depreciation study of the plant in service of the Montana-Dakota Co. – Electric Division ("MDU" or the "Company"), as of December 31, 2017. My detailed report, including my analyses and recommendations, is provided in Exhibit No.__(LEK-1), titled "Calculated Annual Depreciation Rates Application to Plant in Service as of December 31, 2017. The detailed depreciation study report was prepared by me or under my direction.

Q9. Please provide a brief overview of the analyses that led to your depreciation recommendations.

A9. In preparing the depreciation study report, I analyzed the historic plant account data of MDU to prepare an analysis of the Company's past retirement experience. I met with the Company's management and operations representatives to determine the extent to which the historic indications would be reflective of the future retirement patterns. In addition, I toured three Company sub-stations and switch yards, a coal fired thermal generation plant, gas turbine generation facility, the Company service building and yard, and the MDU electric control room. Lastly, I also reviewed the average service life and net salvage indications of many North American based electric utilities to test the results of my analysis against the electric industry peers.

Q10. How is the remainder of your Direct Testimony organized?

A10. Section II provides the scope of my study and a summary of my analyses and conclusions. This section also includes a discussion of the major causes of changes in the depreciation accrual rate and amounts as compared to the last study. Section III provides a background on utility depreciation, depreciation methods and procedures, and a description of changes in the depreciation methods used in this study as compared to prior depreciation studies completed by prior consultants on behalf of MDU. Section IV provides concluding comments.

II. SCOPE OF THE DEPRECIATION STUDY

Q11. Please outline the Scope of the Depreciation Study.

A11. My depreciation study report sets forth the results of the depreciation study for the electric generation, transmission, distribution and general plant assets of MDU Electric Division, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment, as of December 31, 2017. The rates and amounts are based on the Straight-Line Method, incorporating the Average Life Group Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU electric assets in service, as of December 31, 2017, plus the addition of the scrubber pond project at the Lewis & Clark generating station as described by Mr. Jay Skabo.

Q12. Please outline the information included in your depreciation study report.

A12. The depreciation study report is presented in nine (9) sections outlined as follows:

- Section 1 Study Highlights, presents a summary of the depreciation study and results.
- Section 2 Introduction, contains statements with respect to the plan and the basis of the study.
- Section 3 Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.

- Section 4 Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation.
- Section 5 Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 1A, 2, and 2A.
- Section 6 Retirement Rate Analysis
- Section 7 Net Salvage Calculations
- Section 8 Detailed Depreciation Calculations
- Section 9 Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis.

Q13. Was the depreciation study prepared using generally accepted standard methods and practices?

A13. Yes. Previous depreciation studies completed for MDU utilized a widely accepted method for the study of the Company's historic data, known as the Retirement Rate Analysis Method. The Retirement Rate Analysis Method is generally accepted as the correct method to use when aged data is available for review. The aged data used in the last study, through December 31, 2014, was available to be incorporated into our database. Additional reliable aged data, for the period January 1, 2015 through to December 31, 2017, was provided by the Company and incorporated in our database. Given the availability of reliable aged data, I prepared the historic study of mortality history using the retirement rate method. A detailed discussion of the retirement rate analysis is presented in Section 9 of my depreciation study report.

Additionally, the service life study included:

- a review of MDU company practice and outlook, as they relate to plant operation and retirement;
- consideration of current practice in the electric system industry, including knowledge of service life estimates used for other electric system companies; and
- informed professional judgment which incorporated analyses of all of the above factors.

My study of the net salvage percentages was based on detailed study prepared under the standard approach, which has commonly become known as the "Traditional method". Within this method, the net salvage transactions (gross salvage proceeds, re-use salvage and costs of removal or retirement) are compared to the original cost of the item being retired. The analysis is prepared on an actual transaction year basis, for as many years as reliable data is available. The analysis then includes a series of 3-year rolling average bands, 5-year rolling average bands, and life to date bands covering all years of transactional data.

As described in later sections of this evidence, the depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation.

The methods described above are generally accepted for use in the development of depreciation rates for regulated utilities.

Q14. Please provide a summary of the results of the depreciation study.

A14. The study results in an annual depreciation expense accrual related to the recovery of original cost (i.e. excluding net salvage requirement) of $58.4 million, when applied to depreciable plant balances, as of December 31, 2017, as adjusted to include the scrubber pond project at the Lewis & Clark generating station. The study results are summarized at an aggregate functional group level as follows:

Summary of Original Cost, Accrual Percentages and Amounts

Plant Group	**Original Cost**	**Annual Accrual**	
Steam Plant	$552,329,983	4.02%	$22,230,881
Other Production Plant	$458,280,982	3.72%	$17,058,306
Transmission Plant	$295,262,897	1.54%	$4,556,111
Distribution Plant	$412,420,869	3.03%	$12,500,269
General Plant	$30,705,350	6.75%	$2,071,409
Total Plant in Service	$1,749,000,082	3.34%	$58,416,976

Q15. How do the above depreciation rates compare to the currently approved depreciation rates?

A15. The following chart summarizes the proposed composite depreciation rates as compared to the currently approved composite depreciation rates.

Plant Group	**Proposed Depreciation Rate**	**Currently Approved Depreciation Rate**
Steam Plant	4.02%	2.57%
Other Production Plant	3.72%	4.36%
Transmission Plant	1.54%	1.94%
Distribution Plant	3.03%	2.90%
General Plant	6.75%	6.97%
Total Plant in Service	3.34%	2.94%

Q16. Please describe the reasons for the increase in the depreciation rates related to electric production plant.

A16. The largest influence in electric production depreciation rates results from the continued use of a Life Span approach applied to each generation unit. The impact of using the Life Span approach has been more dramatic in recent years because of the large capital spending primarily related to environmental requirements at several of the units.

The use of the Life Span Method is a continuation of the method that was incorporated into the production accounts in the last depreciation study, wherein the depreciation rates for each of the location specific generation accounts were developed from the continued use of a Life Span Method. With the use of a Life Span Method, an interim retirement curve is identified for each property group, based on the analysis as described within Section 3.7 of my depreciation study report. The probable retirement dates for each of the generation plants were, provided to me by MDU, based on an internal MDU analysis of the factors impacting the terminal life of each plant. The life span date is incorporated into the interim survivor curve to develop an average service life and average remaining life, via the Life Span Method, for each of the generation accounts. The life span dates provided are as follows:

Generation Station	**Proposed**	**Currently Used**
Heskett Generating Stations (Units I & II)	2025	2028
Lewis & Clark Generating Station	2025	2025
Coyote Generating Station	2041	2041
Big Stone Generating Station	2046	2046
Wygen III Generating Station	2060	2060

Generation Station	**Proposed**	**Currently Used**
Glendive Turbine – Unit 1	2028	2022
Glendive Turbine – Unit 2	2046	2046
Miles City Turbine	2028	2019
Portable Generators	2047	2047
Heskett Turbine	2057	2057
Diamond Willow Wind Farm	2035	2027
Cedar Hills Wind Farm	2035	2030
Lewis & Clark Turbine	2045	N/A
Ormat Generation Facility	2029	2029
Thunder Spirit Wind Farm	2040	N/A

These life span dates, used in my study for the MDU steam generation plants, are the same dates used in the last depreciation study, with the exception of the Heskett Steam Generation Plant, where the life span date has been modified from December 31, 2028 to December 31, 2025. In the Other Production category, the life span date for the Glendive Turbine - Unit 1 has been extended from December 31, 2022 to December 31, 2028, and the Diamond Willow Wind Farm has been extended from December 31, 2017 to December 31, 2035. As such, the increase in the generation depreciation rate is not significantly caused by changes in the life span dates, but rather by the large amount of capital spending that is required for the generation plants to continue to operate through to the life span date.

Over the period since the last depreciation study, MDU has capitalized $397.4 million into the electric generation plants that incorporate a life span date, representing a 65% increase of investment in electric production (generation) since 2014. Of this amount, the steam generation plants have incurred approximately

$146 million of new investment since 2014, representing a 36% increase. Within the steam generation capital additions, approximately $130 million has been invested at the Big Stone and Lewis & Clark Plants, since 2014. Given that these plants have retained the same life span dates as used in the previous studies, the overall increase in the depreciation rates in the steam generation accounts is largely caused by the level of capital additions at these two plants, which have a limited remaining life.

Within the Other Production accounts, the investment in the new Thunder Spirit Wind Farm facility and the Lewis & Clark RICE units account for approximately $250 million of the total $251.5 million of new capital investment. While the investment in these new production facilities have a limited life span which has an effect to increase the depreciation rates, the life span extensions in other facilities within this group of accounts, more than offsets in impact of the capital additions, resulting in an overall depreciation rate decrease in the Other Production accounts.

Specifically, I note that over $262 million of the $397.4 million invested since 2014 has been invested in generating plants that have a Life Span date of 2040 or sooner. As such, this $262 million has a remaining life of 23 years or less, resulting in a 4.3% or higher depreciation rate for this large amount of investment.

Q17. Please outline the reasons for the decrease in the composite depreciation rate for electric transmission plant.

A17. Within the electric transmission group of assets, the most significant cause of the decrease in depreciation rates is the recognition of a longer average service life of many of accounts. The following is a summary of the proposed average service life estimates compared to the currently used estimates, demonstrating the lengthening of the average service lives in all but two accounts.

Account	Description	Proposed Iowa Curves	Current Iowa Curves
350.20	Land Rights	70-R4	50-R3
352.00	Structures and Improvements	50-R2	45-R2
353.00	Station Equipment	65-R2.5	60-R3
354.00	Towers and Fixtures	60-R4	55-R5
355.00	Poles and Fixtures	60-R3	50-R3
356.00	Overhead Conductors and Devices	70-R4	65-R3
357.00	Underground Conduit	50-R3	50-R3
358.00	Underground Conductors and Devices	50-R3	50-R3

The specific reasons for the average service life extensions for each of the large transmission accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical mortality study are presented for each account, in Section 6 of my report.

Q18. Are the average service life extensions, as noted above, typical for electric transmission assets?

A18. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of electric transmission assets is lengthening throughout North America. While there are a number of factors causing this lengthening of life estimates, the most prevalent reason is the increased focus of utilities in maintaining and life extending the transmission infrastructure. For example, in recent years electric transmission utilities have been pro-active in pole and tower structure management and adding enhanced protection and control equipment within the substations. The specific life expectation of the digital protection and control systems is shorter than the previous electro-mechanical protection and control system, however, the enhanced protection provided within the substation of the new technology has had a life extension influence for transforming and switching equipment.

Likewise, I have noted that the life of transmission line assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by electric transmission utilities. The introduction of pole and tower testing and treatments for wood structures combined with the observation of longer than previously expected life indications for steel structures throughout the industry, have provided electric transmission utilities with the ability to recognize longer lives on these transmission assets. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other electric utilities.

Q19. Please outline the reasons for the increased composite depreciation rate for the electric distribution assets.

A19. The average service life estimates for the electric distribution assets have extended in a similar fashion as described for the average service life extensions of the electric transmission assets. However, in the circumstances of the distribution assets, the need for more negative net salvage percentages has had a depreciation rate increase impact that out-weighed the influence of a decrease due to the life extensions.

The net salvage percentages for the distribution account recommended in my study, as compared to the currently used percentages, are summarized below:

Account	Description	Proposed	Current
360.20	Rights of Ways	0%	0%
362.00	Station Equipment	(10)%	(5)%
364.00	Poles, Towers & Fixtures	(120)%	(95)%
365.00	Overhead Conductor & Devices	(100)%	(85)%
366.00	Underground Conduit	0%	0%
367.00	Underground Conductor & Devices	(40)%	(25)%
368.00	Line Transformers	(20)%	(20)%
369.10	Services	(50)%	(50)%
370.00	Meters	(5)%	(5)%
371.00	Installation on Customers Premises	(15)%	(15)%
373.00	Street Lighting System	(50)%	(40)%

The detailed analysis of the net salvage estimates is provided in Section 7 of my MDU report.

Q20. Is the trend for more negative net salvage percentage, as noted above, typical for electric distribution assets?

A20. Yes. The increased amount of cost of removal expenditures is a common trend throughout North American utilities. In fact, this trend has been the most significant change noted in depreciation studies over the past five years. Accordingly, it has become the most debated topic of depreciation studies filed throughout North America, as well as being a significant topic of discussion at depreciation conferences. At the 2018 Society of Depreciation Professionals conference held in September, there were four presentations regarding the large increase in cost of removal expenditures. This trend has been witnessed over virtually all electric, gas and pipeline utilities. As such, the trend witnessed in my MDU study is consistent with depreciation studies conducted across North America.

Q21. What is causing this trend to increased cost of removal of utility assets?

A21. It is generally accepted that there exist three main causes of increases.

Firstly, as the average age of utility assets continue to be extended, the impacts of inflation becomes more pronounced. For example, in the MDU Account 364 – Distribution Poles and Fixtures, the average service life has been extended in this study from 50 years to 60 years. Also, the last depreciation study increased the average life from 38 years to 50 years for this same account. As such, over the course of two depreciation studies, the indications of average service life have increased from 38 years to 60 years (a 58% increase). As the average service life has increased, the length of time between the original installation of the assets in this account and the estimated average time of retirement of the asset is 58% longer. The net salvage percentage is calculated by dividing the costs to remove the asset in dollars of the time when the asset is removed by the original cost dollar of the time of installation. Given that the major component of cost of removal is labor, this 58% increase in the life expectation, also results in an increased length of time that the labor associated with the removal is 58% longer. When it is considered that in this account, the impacts of inflation of an additional 22 years are recognized in the cost of removal included in my study as compared to the study completed two studies ago, and an additional 10 years when compared to the last depreciation study, it is expected and reasonable to see the increases in cost of removal. To the extent that the average service lives for distribution assets have extended, the impact as described above (for Account 364) applies to a number of the MDU electric distribution accounts.

Secondly, the costs associated with the removal (or retirement) of utility assets must deal with increased environmental and regulatory requirements. For example, the costs related to the safe removal of asbestos and PCB contaminants at substations have greatly increased since the assets were originally installed. Additionally, the utilities are required to deal with the increased level of regulations within areas that are much more densely populated at the time of removal of the assets as compared to when the assets were originally placed into service. As distribution assets are often removed in municipal areas, the need to effectively deal with urban growth and density within the areas adds a significant cost to the removal of the assets that did not exist at the time of the original installation of the assets. When the assets were originally installed, the distribution assets were largely within greenfield developments, whereas now, when the assets are removed, the utility must deal with (for example) applications for road closures and re-routing, noise bylaws, and performing work within and around developed and landscaped yards.

Lastly, as utilities have implemented new and enhanced accounting systems, the ability to better track capital projects has improved the processes to track capital project costs more accurately. This provides the ability for direct charging labor associated to costs of removal specifically to cost of removal. Likewise, in circumstances where the utility uses an allocation of the total project costs to recognize that a portion of the capital project relates to the removal of assets, the advancements in the work order and plant accounting systems provide better information to allow the utility to better develop proper allocation factors.

III. DEPRECIATION METHODS AND PROCEDURES

Q22. How is depreciation defined for a rate regulated utility?

A22. Depreciation defined – "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities".[1] When considering the action of the elements, my average service life recommendations have considered large catastrophic events that have occurred and impacted the life estimates of utility assets across North America through our use of peer analysis . The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, wind storms, large scale flooding, fires, actions of third parties and other natural forces of nature, and these forces of retirement should be included in the determination of the average service life.

1 Federal Energy Regulatory Commission, Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Definitions

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric system utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line Method of depreciation, which was adopted for use in my study.

Q23. Please outline the depreciation methods and procedures used in your depreciation study.

A23. The calculation of annual and accrued depreciation, based on the Straight-Line Method, requires the estimation of survivor curves and the selection of group depreciation procedures, as discussed below.

<u>Depreciation Grouping Procedures</u> - When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. In the determination of the depreciation rates in this study, the use of the Average Service Life Procedure has been continued.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and Average Life Group Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations. Amortization accounting has been continued in this study in a manner largely consistent with the prior study.

A detailed account by account analysis of the factors considered in the selection of my recommended average service life estimates is provided in Section 3.6 of my depreciation study report.

Q24. Please outline any changes that you made in the depreciation method, grouping procedures or remaining life calculations as compared to previous depreciation studies.

A24. The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the Straight-Line Method, the Average Life Group Procedure was applied on a remaining life basis. However, I note that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintage approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a Calculated Accumulated Depreciation ("CAD") weighted calculation in the textbook Depreciation Systems, by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994, under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies was based on a broad averaging of the composite remaining life. This method is also discussed as the

Amortization Method in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

In the manner in which I developed the remaining life calculations, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. Specifically, my calculations are made for each vintage surviving investment as of the date of the study (December 31, 2017), and then composited into a calculation for the account or group as a whole as compared to applying one overall composite life to all vintages as done in prior studies. My calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account. Consistent with the plant accounting systems of most utilities, MDU does not track the booked accumulated depreciation reserve by vintage within each account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. As such, the accumulated depreciation by account is allocated within the account to each vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates and the achieved age of each vintage.

2 The estimated remaining life of each vintage with each account. The estimated remaining life of each vintage is a direct function of the achieved age of

each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving, as of December 31, 2017.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on a CAD approach to the remaining life calculations is widely considered to be the most accurate. I agree and view this methodology as the correct and most appropriate calculation.

IV. CONCLUDING REMARKS

Q25. What is your conclusion with respect to Montana-Dakota's proposed Depreciation expense?

A25. My conclusion is that Montana-Dakota's requested depreciation rates, resulting in a composite depreciation rate of 3.34%, reasonably reflects the annual consumption of the undepreciated service value of the utility plant in service. Therefore, the use of the depreciation rates as presented in my report, by account, will provide for an appropriate amount of depreciation expense in the Company's revenue requirement. Therefore, I recommend that the proposed depreciation rates set forth in the depreciation study, that I prepared for this proceeding, be adopted by the

Commission for regulatory purposes as well as by the Company for financial reporting purposes.

Q26. Does this conclude your Direct Testimony?

A26. Yes, it does.

Larry E. Kennedy
Vice President

Larry Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 35 years. As Vice President, Concentric Advisors ULC, Larry is responsible for depreciation studies for gas and electric utilities including generation facilities, and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC for over 17 years where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated Canadian utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TransCanada Pipelines) for 3 years as a Depreciation Specialist. In these roles, Mr. Kennedy often led cost control and accounting teams to ensure that financial controls and accurate financial information was captured and that contractual commitments of contractors were followed. In 1985, Mr. Kennedy was assigned to the Norman Wells Pipeline project to lead an internal audit review of the Interprovincial Pipelines Limited Norman Wells Pipeline project. In 1995, Mr. Kennedy was assigned to the Enbridge System Expansion project to ensure proper cost controls were in place during the build of a new large diameter pipeline extending from Hardisty, Alberta to Superior, Wisconsin.

Mr. Kennedy has provided expert witness testimony related to depreciation and capital accounting issues before several Canadian provincial regulatory bodies, the National Energy Board of Canada and the Municipal Government Board of Alberta. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy has presented depreciation and capital accounting related topics to the Society of Depreciation Professionals (SDP), Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission, and Canadian Energy Pipeline Association. Mr. Kennedy is a Past SDP President.

REPRESENTATIVE PROJECT EXPERIENCE

- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board. Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the

estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004 additional depreciation studies were filed in 2005, 2010 and 2012. The 2010 and 2012 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards.

- ATCO: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta Assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities (NWT) Inc. and the distribution assets of Northland Utilities (Yellowknife) Inc. ATCO Electric studies were submitted to the AUC for review, while the Northland Utilities Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to Yukon Public Utilities Board. ATCO Gas studies were prepared in 2010 and were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements.

- BC Hydro: This assignment included the development of an average service life study for all of the BC Hydro's electric generation, transmission, distribution and general plant assets. The study, which was prepared for submission to the British Columbia Utilities Commission ("BCUC), included development of depreciation policy for the company, development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, and the compilation of a detailed report. The assignment included the support of the study through the regulatory process. Mr. Kennedy has also completed a review of the cost allocation procedures and practices which was filed with the BCUC in 2010.

- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted on issues regarding IFRS compliance and required componentization.

- Enbridge Gas Distribution Inc.: Full and Comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Inc.: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the BCUC in 2005, 2010 and 2011 encompassing both the FortisBC electric and natural gas companies. FortisAlberta studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates.

- International Financial Reporting Standards (IFRS): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association, and to the British Columbia Utilities Commission on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada.

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the

Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- Newfoundland and Labrador Hydro: Mr. Kennedy developed a comprehensive depreciation study that included the development of depreciation policy and rates for Newfoundland and Labrador Hydro. The study provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 study was the subject of Regulatory Review in 2012.

- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives the regulated assets were completed in 2011 and 2013, and were submitted to the Ontario Energy Board for review.

- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012.

- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the National Energy Board of Canada ("NEB") included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002, and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011. The 2011 study was fully supported through an appearance before the NEB in 2012.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2017 – Present)
Vice President

Gannett Fleming, Inc. (1999-2017)
Vice President

EDUCATION

Diploma in Applied Arts – Business Administration, Northern Alberta Institute of Technology

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Society of Depreciation Professionals (former President)

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2000	**AltaGas Utilities Inc.**	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	**ENMAX Power Corporation**	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	**Centra Gas British Columbia**	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	**ENMAX Power Corporation**	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	**Centra Gas Manitoba**	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	**Manitoba Hydro**	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	**City of Calgary**	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	**City of Calgary**	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2004	**AltaGas Utilities Inc.**	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2005	**Yukon Energy Corporation**	Yukon Energy Corporation	Yukon Utilities Board	N/A
2005	**NOVA Gas Transmission Ltd.**	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	**FortisAlberta Inc.**	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	**ATCO Electric**	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	**The City of Red Deer**	The City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729

YEAR	**CLIENT**	**APPLICANT**	**REGULATORY BOARD**	**PROCEEDING NUMBER**
2005	**Northland Utilities (Yellowknife) Inc.**	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	**Northland Utilities (NWT) Inc.**	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	**ENMAX Power Corporation**	ENMAX Power Corporation-Transmission	Alberta Energy and Utilities Board	N/A
2005	**FortisBC, Inc.**	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	**New Brunswick Board of Commissioners of Public Utilities**	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	**British Columbia Transmission Corporation**	**British Columbia Transmission Corporation**	**British Columbia Utilities Commission**	N/A
2005	**Manitoba Hydro**	**Manitoba Hydro**	**Manitoba Public Utilities Board**	N/A
2005	**Centra Gas Manitoba**	**Centra Gas Manitoba**	**Manitoba Public Utilities Board**	N/A
2005	**FortisAlberta Inc.**	**FortisAlberta Inc.**	**Alberta Energy and Utilities Board**	N/A
2006	**BC Hydro**	BC Hydro	British Columbia Utilities Commission	N/A
2007	**Enbridge Pipelines Limited**	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	**FortisAlberta Inc.**	FortisAlberta Inc.	Alberta Energy and Utilities Board	1514140
2007	**Kinder Morgan**	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2008	**ATCOGas**	ATCOGas	Alberta Utilities Commission	1553052
2008	**Heritage Gas Ltd.**	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2008	**ENMAX Power Corporation**	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	**City of Lethbridge Electric System**	City of Lethbridge	Alberta Utilities Commission	N/A
2009	**AltaGas Utilities Inc.**	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2010	**Enbridge Pipelines Limited - Line 9**	Enbridge Pipelines Limited-Line 9	National Energy Board of Canada	N/A
2010	**Kinder Morgan**	Kinder Morgan	National Energy Board of Canada	N/A
2010	**Pacific Northern Gas**	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	**SaskPower**	SaskPower	Internal Review Committee	N/A
2011	**Fortis Alberta Inc.**	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	**Qulliq**	Qulliq	Utilities Rates Review Council	N/A
2011	**Heritage Gas Ltd.**	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	**ATCO Electric**	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2012	**Newfoundland and Labrador Hydro**	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	**City of Red Deer**	City of Red Deer	Alberta Utilities Commission	1608641
2012	**Enbridge Gas Distribution Inc.**	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2012	**Northwest Territories Power Corporation**	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2015	**GazMetro**	GazMetro	La Regie de L'Energie	N/A
1999	**ENMAX Corporation**	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2001	**City of Calgary**	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	**City of Calgary**	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	**City of Calgary**	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2003	**AltaLink Management Ltd**	AltaLink Management Ltd	Alberta Energy and Utilities Board	1279345
2003	**TransCanada Pipelines Limited**	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2003	**City of Calgary**	ATCOGas	Alberta Energy and Utilities Board	1275466
2003	**City of Calgary**	ATCO Electric	Alberta Energy and Utilities Board	1275494
2004	**NOVA Gas Transmission Limited**	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	**ENMAX Power Corporation**	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	**Westridge Utilities Inc.**	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2004	**Heritage Gas Ltd.**	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	**Central Alberta Midstream**	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	**AltaLink LP**	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	**Central Alberta Midstream**	Central Alberta Midstream	Municipal Government Board of Alberta	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	**AltaGas Utilities Inc.**	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	**ATCO Power**	ATCO Power	Municipal Government Board of Alberta	N/A
2005	**ENMAX Power Corporation**	ENMAX Power Corporation-Distribution Assets	Alberta Energy and Utilities Board	1380613
2006	**AltaLink LP**	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	**Imperial Oil Resources Ventures Limited**	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2008	**ATCO Electric**	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2009	**Fortis Alberta Inc.**	Fortis Alberta Inc.	Alberta Utilities Commission	1605170
2010	**Gazifere**	Gazifere	La Regie de L'Energie	R-3724-2010
2010	**ATCO Electric**	ATCO Electric	Alberta Utilities Commission	1606228
2011	**ATCO Gas**	ATCO Gas	Alberta Utilities Commission	1606822
2011	**GazMetro**	GazMetro	La Regie de L'Energie	R-3752-2011
2011	**AltaGas Utilities Inc.**	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	**AltaLink**	AltaLink	Alberta Utilities Commission	1606895
2011	**FortisBC Energy, Inc.**	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	**TransAlta Utilities Corporation**	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	**FortisBC, Inc.**	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	**TransCanada Pipelines Limited**	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2012	**Manitoba Hydro**	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2013	**IntraGaz Incorporated**	IntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	**AltaLink LP**	AltaLink LP	Alberta Utilities Commission	1608711
2013	**Yukon Electrical Company Limited (YECL)**	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	**ENMAX Power Corporation**	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2014	**Enbridge Gas Distribution**	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2015	**Manitoba Hydro**	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	**AltaLink LP**	AltaLink LP	Alberta Utilities Commission	Proceeding 3524 Appearance Pending
2015	**ATCO Electric**	ATCO Electric	Alberta Utilities Commission	Proceeding 20272 Appearance Pending
2015	**EPCOR Distribution & Transmission**	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	**EPCOR Distribution & Transmission**	EPCOR Distribution & Transmission	Alberta Utilities Commission	Appearance Pending
2015	**Newfoundland and Labrador Hydro**	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	Appearance Pending
2015	**FortisBC Energy, Inc.**	FortisBC Energy, Inc.	British Columbia Utilities Commission	Appearance Pending
2015	**FortisBC, Inc.**	FortisBC, Inc.	British Columbia Utilities Commission	Appearance Pending
2015	**Gazifere**	GazMetro	La Regie de L' Energie	Appearance Pending

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___

Direct Testimony
of
Travis R. Jacobson

Q. Would you please state your name and business address?

A. Yes. My name is Travis R. Jacobson, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Analysis Manager for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Regulatory Analysis Manager?

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments, and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. **Would you please describe your education and professional background?**

A. I graduated from Minot State University with a Bachelor of Science degree in Accounting and I am a Certified Public Accountant (CPA). I started my career with Montana-Dakota in 1999 as a financial analyst in the Financial Reporting area and during my tenure with the Company have held positions of increasing responsibility, including Supervisor, Financial Reporting & Planning and Manager, Financial Reporting & Planning before attaining my current position.

Q. **Have you testified in other proceedings before regulatory bodies?**

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of North Dakota and Wyoming, and the Public Utilities Commissions of Minnesota and South Dakota.

Q. **Are you familiar with the books and records of Montana-Dakota and the manner in which they are kept?**

A. Yes. Montana-Dakota's books and records are kept in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the per books cost of service for the twelve months ended December 31, 2017, the pro forma cost of service reflecting known and measurable adjustments that will occur by December 31, 2018, the pro forma cost of service supporting the request for interim rate relief and the calculation of the interim and final revenue deficiencies. I will present proposed changes to Rate 58 - Fuel and Purchased Power Cost Tracking Adjustment and I will present the Rate 56 - Electric Tax Tracking Adjustment base tax to be established in conjunction with this filing.

Q. What statements, schedules, and exhibits are you sponsoring?

A. I am sponsoring Statements C through E, Statement G, Statement H, pages 1 through 2 and 6 through 7, Statements I through K, and Part A of Statement O. Also, the Interim, Statements C through E, Statements G, Statement H, pages 1 through 2 and 4, Statements I through K, and Statement O. Lastly, I am sponsoring Exhibit No.___(TRJ-1), the calculation of the final revenue requirement, Exhibit No.___ (TRJ-2), the proposed Rate 35 and 58 fuel and purchased power cost tracking adjustment tariffs, Exhibit No.___ (TRJ-3), the revenue requirement impact of each income statement and rate base pro forma adjustment proposed by the Company, and Exhibit No.___ (TRJ-4), the calculation of the interim revenue requirement.

Pro Forma Revenue Requirement

Q. What were the results of Montana electric operations for the twelve months ended December 31, 2017?

A. Rule 38.5.175, pages 1 and 2 show the per books income statement and rate base for total Company and Montana. As shown on page 1, Montana electric operations had a return on rate base of 5.524 percent for the twelve months ended December 31, 2017. The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement or rule listed. Pages 3 through 5 list the pro forma adjustments to operating revenues, expenses, and rate base. All adjustments were calculated on either a Montana specific basis or on a total Company basis and allocated to Montana, as indicated on the statement or schedule detailing each adjustment.

Q. How was the per books cost of service allocated to Montana?

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense, and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

Q. What criteria were used to determine the pro forma adjustments?

A. The pro forma adjustments to operating revenue, expenses, and rate base were based on known and measurable changes occurring by December 31, 2018, conformed to past Commission practices and are listed on pages 3 through 5 of Rule 38.5.175. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

Q. Would you describe the pro forma adjustments to the income statement and rate base?

A. Yes. The adjustments to the income statement are summarized in Rule 38.5.175, page 3 and 4 and consist of adjustments to revenue, operation and maintenance expenses, depreciation expense, taxes other, and current and deferred income taxes. The adjustments to rate base are summarized on page 5 and include plant, accumulated reserve for depreciation, and associated additions and deductions.

Pro Forma Income Statement

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Rule 38.5.164, Statement H, page 1.

Adjustment No. 1 is an increase of $1,448,569 in retail sales revenue that is based on pro forma 2017 volumes and current rates reflecting the pro forma fuel and purchased power expense as described by Ms. S. Bosch. Pro forma retail sales revenue includes Rate 56 - Electric Tax Tracking Adjustment revenues (TTA) based on the rates effective January 1, 2018 as authorized in Docket No. D2017.9.72. Pursuant to paragraph 3(b) of Rate 56, a base tax amount shall be updated in a general rate case and will be expressed as a percentage to be applied to the basic service charge, energy charge, and demand charge revenue. Therefore, the total revenue shown in this filing includes Montana direct ad valorem taxes of $4,066,914, based on the Montana Department of Revenue’s 2018 Valuation Assessment, to enable Montana-Dakota to update the base tax percentage. At the same time, the inclusion of TTA revenue is necessary to properly reflect the pro forma level of late payment revenue in Adjustment No. 3 below as well as the uncollectible accounts expense (Adjustment No. 13) and the Montana Consumer Counsel/Public Service Commission revenue taxes (Adjustment No. 26). The following table presents the total Montana direct ad valorem taxes and shows the matching of the base tax revenue amount which will be used as the basis for updating the base tax percentage.

Rate 56 - Electric Tax
Tracking Adjustment

Rule 38.5.174, Statement K, Page 1		
Per Books Montana Ad Valorem Taxes	$ 3,649,093	
Pro Forma Adjustment No. 23	417,821	
Pro Forma Montana Ad Valorem Taxes	$ 4,066,914	
Electric Tax Tracking Adjustment Base Revenue		
Annualized Revenue at Current Rates	$ 3,117,397	1/
2018 Tax Tracking Adjustment (Eff. 1/1/2019)	379,618	2/
Base Tax Tracking Adjustment True-Up	569,899	3/
Pro Forma Base Tax Revenue	$ 4,066,914	

1/ Rule 38.5.164, Statement H, Page 3.
2/ Estimated increase in 2018 ad valorem tax to be collected through the TTA over the 2017 ad valorem tax amount in current rates.
3/ Additional ad valorem tax revenue necessary to be recovered through the base percentage upon disposition of the rate case based on the total pro forma tax expense.

Adjustment No. 2 decreases revenue by $226,695 to reflect the elimination of sales for resale as these revenues are passed back to customers through the Fuel & Purchased Power Adjustment.

Adjustment No. 3 is comprised of several adjustments to miscellaneous operating revenues, a reduction of $6,374 including annualized rent, late payments based on a three year average of late payments to retail sales revenue, three year average KVAR penalty revenue and five year amortization of gains and losses, and a reduction of $887,052 in transmission service revenue, for an overall decrease of $890,402.

The lower transmission service revenue of $887,052 is largely related to lower revenue credits received through MISO and Southwest Power Pool (SPP). The Company is proposing to recover transmission service revenue in a manner consistent with fuel and purchased power expenses through the Fuel & Purchased Power cost tracking adjustment as shown in Adjustment No. 4 and described later in my testimony and in the testimony of Mr. D. Neigum.

Several adjustments to miscellaneous operating revenue were based on the actual revenue recorded during the first half of 2018 and annualized to reflect the pro forma period, including Rent from Property of $25,733 as well as other immaterial changes. The pro forma late payment revenue reflects a three-year average of late payment revenue to retail sales revenue for a decrease of $1,710. Montana-Dakota is using a three-year average of KVAR penalty revenue as a representative level of KVAR penalty revenue resulting in a reduction of $3,083. Gains and losses reflect an amortization on sale of plant over a five-year period resulting in a reduction of $21,837.

Q. **What adjustments were made to operation and maintenance (O&M) expenses?**

A. The adjustments to operation and maintenance expenses are summarized in Rule 38.5.156, Statement G, page 1 and contained in Rule 38.5.157, Statement G.

Adjustment No. 4 increases the cost of fuel and purchase power expense by $1,129,628 that reflects current MISO market pricing, normal outage schedules, the Thunder Spirit wind facility expansion, and the Company's proposal to reclassify sand expense from Production O&M expense and recover this expense in the same manner as reagents through the fuel and purchased power cost tracking adjustment.

Adjustment No. 10 reflects the removal of sand expense from Production O&M expense. Sand is used, along with lime, at the Heskett Station as a pollution control agent and its usage is variable and dependent on the amount of coal burned.

Adjustment No. 4 also reflects a reduction of regional transmission organization (RTO) transmission service expenses of $275,777 based on the current MISO and SPP tariff rates. The primary reductions are related to MISO Schedule 26 & 26a and SPP Schedule 9. Montana-Dakota is proposing to recover RTO transmission service expenses through the fuel and purchased power cost tracking adjustment. As mentioned previously in my testimony, Adjustment No. 3 reflects the pro forma adjustments to transmission service revenue in other operating revenues. Currently, RTO transmission service expenses and transmission service revenue are components of base rates while MISO and SPP energy market charges are recovered through the fuel and purchased power cost adjustment. As discussed in the testimony of Mr. D. Neigum, Montana-Dakota's participation in the RTOs has provided significant benefits in terms of reduced energy costs. The Company's proposal will provide a more appropriate relationship between the RTO transmission service charges incurred with the costs and benefits associated with participation in the energy markets of the same RTOs. Therefore, the Company's proposal reflects the net transmission charges incurred by the Company in its Rate 35 and 58 revisions.

Q. How were the pro forma labor and benefits developed?

A. Labor is shown on page 5 of Statement G, Adjustment No. 5. The pro forma labor was developed by applying the percentage increase in total Company labor costs to the actual 2017 Montana labor expense. Pro forma total Company labor costs were based on the application of an increase of 3.0 percent for union employees and 3.4 percent for non-union employees effective in 2017. In addition, bonuses, commissions and incentive compensation or pay at risk expenses have been adjusted to reflect targeted incentive levels as a percentage of straight time and vacation. This results in an overall net decrease in labor expense of $45,528 or 0.85 percent.

Benefits are shown on page 6 of Statement G, Adjustment No. 6, for an overall increase of $63,444. Benefits expense consists of medical/dental insurance, pensions, post-retirement, 401-K, workers compensation, and other benefits (primarily disability insurance). Each of these items were adjusted individually using current information and applying the percentage change to each type of benefit.

Medical and dental expenses are increasing 5.2 percent to reflect the premiums in effect January 1, 2018. Pensions expense decreased 4.61 percent and post-retirement expense decreased by 5.04 percent from 2017 levels. The decrease in expense is primarily due to favorable returns on pensions and post retirement trust assets. 401-K, workers compensation, and other benefits are tied to labor costs and were increased by 3.24 percent to reflect the overall average increase in straight time labor.

Q. Would you describe the other adjustments made to O&M expense?

A. Yes. Montana-Dakota has agreements with other utilities which provide access to their facilities to allow the Company to provide service to its customers. As such, the Company incurs a facility charge for the access to that facility. Adjustment No. 7 for facility charge expense shows a decrease of $148,036 related to a prior period adjustment for the use of transmission facilities prior to Montana-Dakota's membership in SPP.

Adjustment No. 8 for subcontract labor expense shows an increase of $418,651 that reflects increased charges under existing maintenance agreements for Thunder Spirit, including the expansion project, and Glen Ullin Station (Ormat).

Adjustment No. 9 reflects the expenses associated with the Company's Big Stone and Coyote generating stations to reflect operations for 2018. The adjustment reflects major overhaul costs for Big Stone station as the Company normally performs major annual overhauls on a rotating basis. No major annual overhauls were scheduled in 2017; however, the costs are expected to continue on an annual basis in the future and are included in this adjustment. The total increase for Big Stone and Coyote expense is $449,870.

As noted previously, Adjustment No. 10 for sand expense shows a decrease of $109,254 that reflects the removal of sand from base rates as the Company is proposing to recover this cost through the fuel and purchased power cost tracking adjustment as shown in Adjustment No. 4.

Adjustment No. 11 shown on page 11 for vehicles and work equipment expense reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, skid steers and excavators, including the costs of fuel, insurance, maintenance, and depreciation expense. This adjustment reflects an increase of $71,493 due to the change in the depreciation component of the expense. It is calculated based on the pro forma plant and proposed depreciation rates in Statement I. The depreciation component on these items are not charged to depreciation expense but rather are charged to a clearing account where they are then recorded in O&M expense as the vehicles or work equipment are used. The pro forma expense reflects the changes in plant in service as well as the proposed depreciation rates as supported in the Direct Testimony of Mr. L. Kennedy.

Adjustment No .12 for company consumption expense reflects expense for electric and natural gas consumption in Company buildings. The electric component is projected to increase $2,247. The natural gas component is expected to decrease $3,540 based on the decrease in normalized firm sales and the July 2018 cost of gas. The net change is a decrease of $1,293 for company consumption expense.

Adjustment No. 13 for uncollectible accounts expense reflects an increase of $44,275 based on the three-year average of net write-offs to pro forma retail sales revenues.

Adjustment No. 14 for advertising expense reflects a decrease of $9,380. Pursuant to past Commission policy, general promotional advertising expense has been eliminated. Informational and institutional advertising expenses were also adjusted to exclude advertising not directly applicable to Montana electric operations.

Adjustment No. 15 for insurance expense reflects an increase of $27,997 at current levels for 2018. Property insurance was adjusted to reflect the Thunder Spirit expansion for $32,160 and self-insurance expense was adjusted to reflect a five-year average of claims and related expenses paid.

Adjustment No. 16 shown on page 16 for software maintenance expense is an increase of $78,220 and is based on the current and estimated levels of expense and implementation of new software.

Adjustment No. 17 for industry dues expense reflects an increase of $8,337 at current 2018 levels. The industry dues are directly assigned or allocated to Montana and appropriately included in the pro forma expense level. In compliance with past Orders, 40 percent of dues to the local Chambers of Commerce have been excluded.

Adjustment No. 18 for rent expense is a decrease of $47,460. The decrease reflects the elimination of a Lewis & Clark rental and a reduction in corporate expenses.

Annual easements expense, Adjustment No. 19, reflects an increase of $66,926 for the increased easement expense for Cedar Hills and Thunder Spirit, including the expansion at Thunder Spirit.

Lastly, adjustment No. 20 for regulatory commission expense reflects the anticipated cost of this filing, a three-year average of ongoing regulatory commission expense, and the expenses related to the common and electric depreciation studies and decommissioning studies amortized over five years. The adjustment is an increase of $52,140.

The items adjusted individually above represent approximately 96 percent of total Montana electric O&M expense, as shown on page 21. The remaining items, which make up approximately 4 percent of Other O&M expense, are assumed to remain flat.

Q. What adjustments were made to depreciation expense?

A. The adjustments to depreciation expense are summarized in Rule 38.5.165, Statement I, page 1.

Adjustment No. 21 is comprised of three components. First, the adjustment shows the annual depreciation expense based on the average pro forma level of plant in service excluding the Thunder Spirit expansion. Concentric Energy Advisors (CEA) consultants prepared a depreciation study, at the Company's request, for electric assets based on the plant balances at December 31, 2017. The electric study is supported in the testimony of Mr. L. Kennedy. The common depreciation rates proposed in this filing are consistent with depreciation rates approved in the last electric rate case in Docket No. D2015.6.51. The depreciation rates are shown on Statement I, pages 3 through 7. The total pro forma change to depreciation expense is $2,783,770.

Adjustment No. 21 also reflects the impacts of the latest decommissioning studies and related pro forma decommissioning balances. Upon the conclusion of Docket No. D2015.6.51, Montana-Dakota began refunding the over collected balance in the amount of $1,342,439 per year. Montana-Dakota has updated the decommissioning studies for all generating units except those jointly owned for this filing. The updated studies reflect the costs to comply with the most recent decommissioning requirements and salvage estimates. The current estimate for Montana's share of the decommissioning costs indicates that the unamortized balance as of December 31, 2018 is $52,318 short of the required decommissioning balance. This balance is proposed to be recovered over three years. Therefore, the Company must cease the annual refunding of $1,342,439. The Thunder Spirit expansion was not part of the decommissioning studies, so the decommissioning cost was estimated based on the per turbine decommissioning cost of the existing Thunder Spirit facility. The decommissioning cost of the Thunder Spirit expansion is estimated to be $3,214,039 with Montana's share of $841,777 to be collected over the 25-year life of the facility or $33,671 annually. The total pro forma adjustment eliminates the refunding of $1,342,439, recovers $17,439 over a three year period to eliminate the under funded balance for all existing facilities, and recovers $33,671 annually for the Thunder Spirit expansion for a total adjustment of $1,393,549.

The last component of Adjustment No. 21 is related to the amortization of the preferred stock redemption costs. On April 1, 2017, Montana-Dakota redeemed all outstanding preferred stock. Preferred stock has characteristics of both debt and equity. For instance, only

$180,000 of the $685,000 in dividends paid each year are deductible on the Company's tax return. The quarterly dividends paid are based on a stated rate of 4.5 and 4.7 percent similar to debt. $20 million of long-term debt issued in the first quarter of 2017 provided an opportunity to redeem the preferred stock and replace it with long term debt with a stated interest cost of 3.36 percent. At the same time, all of the interest is deductible for tax purposes which further reduces the revenue requirement. The result of the redemption is a lower overall cost of capital.

As discussed in the testimony of Ms. T. Nygard, a call premium of $600,000 was incurred upon redemption of preferred stock. The call premium has been deferred on the Company's books. The Company is now proposing to include this regulatory asset in its rate base and to amortize the balance over the life of the long-term debt of 15 years. An analysis has been prepared which demonstrates the overall net benefit of the redemption, inclusive of the rate base impact, is beneficial to Montana-Dakota's customers. Therefore, this item has been reflected in the revenue requirement in a manner similar to the unamortized loss on debt

The 2017 per books reflects a one-time adjustment in the amount of $88,005 that must be removed to reflect normalized expenses. The annual amortization of the preferred stock expense of $5,867, based on a

15-year amortization, is combined with the one-time adjustment for a total pro forma adjustment of $93,872.

Adjustment No. 22 shows the annual depreciation expense of $904,907 for the Thunder Spirit expansion based on the pro forma year end plant balance.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are summarized in Rule 38.5.173, Statement K, page 1 and contained in Rule 38.5.174, Statement K.

Adjustment No. 23 for ad valorem taxes is an overall increase of $441,451 that reflects Montana ad valorem taxes, allocated ad valorem taxes, and tribal ad valorem taxes. The direct Montana ad valorem taxes increased $417,821 and was based on the 11.45 percent increase from the Department of Revenue's final 2018 ad valorem valuation for Montana-Dakota's electric properties. As previously mentioned in my testimony, Montana-Dakota has included the pro forma Montana direct ad valorem tax increase in order to update the base tax percentage applicable under Rate 56 - Electric Tax Tracking Adjustment upon disposition of this rate case. The Company will file an update to Rate 56 in late 2018 with changes to be effective January 1, 2019; however, the base tax percentage is not allowed to be adjusted in that filing. Therefore, the revenue collected under the January 1, 2019 TTA rates will not be matched with the total tax expense until the base tax percentage is updated upon conclusion of the case.

Adjustment No. 23 also restates the allocated ad valorem taxes to reflect an increase of $16,460 based on the change in the average allocated pro forma plant balances. Lastly, the tribal ad valorem taxes increased $7,170 to reflect the elimination of an out of period adjustment included in the 2017 per books expense and an annualized 2018 actual expense.

Adjustment No. 24 for payroll taxes is a decrease of $2,993 based on the ratio of payroll taxes to labor expense for 2017 applied to pro forma labor expense.

Adjustment No. 25 for electric production taxes is an increase of $49,607 that reflects the pro forma load resources included in Adjustment No. 4, including generation from the Thunder Spirit expansion.

Adjustment No. 26 for Montana Consumer Counsel Tax and Public Service Commission taxes reflect a decrease of $135,376 based on applying the tax rate, effective October 1, 2017, to the pro forma revenue and miscellaneous revenue.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are summarized in Rule 38.5.169, Statement J, page 1.

Adjustment No. 27 for interest expense is an increase of $375,205 based on the pro forma rate base and cost of debt, shown on page 2. Interest is deductible for tax purposes and interest expense is calculated on the pro forma rate base using the weighted cost of debt from Rule 38.5.146, Statement F, page 1.

Adjustment No. 28 for tax/book depreciation differences and the associated deferred taxes on plant in service as of December 31, 2017, pro forma plant additions, and the Thunder Spirit expansion are shown on page 3.

Adjustment No. 29 is an adjustment to eliminate the preferred stock dividend deduction shown on page 4. As discussed earlier in my testimony, with the redemption of the preferred stock, the Company is no longer able to deduct a portion of the preferred stock dividends from its income each year. 2017 was the last year of the preferred stock dividend deduction. Alternatively, the Company is able to deduct 100 percent of the interest associated with the debt that replaced the preferred stock.

Adjustment No. 30 is the pro forma adjustments to current income taxes on operating revenues and expenses as shown on page 5.

Adjustment No. 31 for production tax credit (PTC) is related to energy produced at the Company's wind generating facilities and was adjusted to reflect a credit of 2.4 cents per kWh of production for a total increase in the federal income tax credit of $735,505. The increase includes generation from the Thunder Spirit expansion and a reduction in generation for Diamond Willow as 13 of 20 turbines reached the ten years in service date and are no longer eligible to receive the production tax credit. During 2017, Montana-Dakota was not able to utilize all earned PTCs; however, the PTCs that were not utilized offset deferred income taxes resulting in no change in net income tax.

Adjustment No. 32 and Adjustment No. 34 are the adjustments to current and deferred income taxes to reflect the Tax Cuts and Jobs Act of 2017 (TCJA) as shown on page 7 and 9. The TCJA was signed into law on December 22, 2017 and incorporated a number of changes which will impact Montana-Dakota's Montana electric operations. The primary impact of the TCJA is the reduction in the corporate income tax rate from 35 percent to 21 percent. The rate reduction has a two-fold effect:

1. A reduction in prospective income taxes on the Company's income statement beginning January 1, 2018; and

2. The Company was required to remeasure utility-related deferred taxes based on the 21 percent tax rate as of December 31, 2017 with a regulatory liability established representing the difference between the old and new tax rate referred to as the excess deferred taxes (EDITs).

Of the total EDITs recorded as a regulatory liability, the plant related EDITs are the most significant. Plant related EDITs are comprised of both protected and non-protected differences; however, the total must be considered if an alternative amortization method is to be proposed for the non-protected balances. The non-protected balance is $15,333 (asset) while the protected balance is $17,434,586 (liability) for a net plant related balance of $17,419,253. Montana-Dakota proposes that all plant related EDITs established at the end of 2017 be amortized over the average remaining life of the assets, referred to as the Average Rate Assumption Method (ARAM). Consistent with the Internal Revenue Service's guidelines, ARAM is used because the plant related EDITs may not be returned any faster than over the remaining lives of the underlying assets. The annual amortization begins in the period when tax depreciation for each asset is less than book depreciation for the same asset. With that in mind, the ARAM amortization will vary from year to year.

Adjustment No. 32 and Adjustment No. 34 reflect an adjustment to the per books 2017 actual results to reflect the impact of the lower federal tax rate on current and deferred income taxes. Adjustment No. 32 reflects an increase in current income tax expense of $1,671,805 which is more than offset by a decrease in deferred income tax expense of $2,192,872 for a net benefit of $521,067. Adjustment No. 35 is the plant and non-plant excess deferred taxes shown on page 10 in the amount of $438,305 (reduction in deferred income tax expense) and $17,187 (increase in deferred income tax expense), respectively.

Adjustment No. 33 is the closing/filing and prior period adjustments for the current and deferred income taxes. Adjusted current and deferred income taxes match those calculated for Montana and conform to past Commission practices.

Pro Forma Rate Base

Q. How was the rate base developed?

A. The pro forma rate base is based on the average 2017 rate base and reflects known and measurable adjustments that will occur within twelve months beyond December 31, 2017. The resulting rate base is stated on an average basis, except as noted below. The pro forma adjustments to rate base are summarized in Rule 38.5.175, page 5.

Adjustment A shown in Rule 38.5.123, Statement C, pages 2 through 8 are the known and measurable plant additions that will be in service by December 31, 2018. The increase of $13,911,910 includes additions to production, transmission, distribution, general, and common plant.

Adjustment B shown in Rule 38.5.123, Statement C, page 9 is Montana's allocated portion of the Thunder Spirit expansion. This production investment is $22,622,671 and has been annualized to reflect the plant additions as if they were in service the entire year. Fuel and purchased power cost savings attributable to the energy produced by this project will flow to customers immediately as offsets to costs recovered through the fuel and purchased power cost adjustment upon commercial operation in mid-October 2018. The energy and production tax credits associated with generation will become an immediate benefit to customers in the form of reduced fuel and purchased power costs. This project is discussed in more detail in the testimony of Mr. D. Neigum. All related adjustments were also annualized, including the energy generated which provides an offset to fuel and purchased power costs, and the related production tax credit associated with wind generation.

Adjustment C shown in Rule 38.5.133, Statement D, page 2 is the accumulated reserve for depreciation on plant additions, excluding the Thunder Spirit expansion, for $12,699,878 that reflects the average pro forma level to coincide with the average pro forma plant levels.

As discussed earlier in my testimony, the decommissioning reserve as of December 31, 2017 was shown along with the accumulated reserve for depreciation in the amount of $7,157,700 reflecting the estimated decommissioning balance related to Montana's electric customers. An additional balance was included as a credit to the rate base in the Additions section of the rate base. Adjustment C includes the reclassification of the remaining pro forma balance of $3,280,963 as of December 31, 2018 as the decommissioning studies now reflect that the Company is no longer in an over accrued position for decommissioning costs. The current year's decommissioning amortization of $51,110 is also included in this adjustment.

Adjustment D shown in Rule 38.5.165, Statement I, page 8 is the accumulated reserve for depreciation on Montana’s allocated plant addition for the Thunder Spirit expansion of $904,907 which reflects a full year of depreciation.

The working capital adjustments are summarized in Rule 38.5.141, Statement E, page 1.

Adjustment E, shown in Rule 38.5.143, Statement E, page 1 reflects a thirteen-month average balance, with actual balances through May 2018 for material and supplies for an increase of $32,381. The remaining pro forma months of 2018 are based on the corresponding 2017 monthly balances.

Adjustment F, shown on page 2 reflects a thirteen-month average balance, with actual balances through May 2018 for fuel stores representing a decrease of $20,537. The remaining pro forma months of 2018 are based on the corresponding 2017 monthly balances.

Adjustment G, shown on page 3 reflects a thirteen-month average balance, with actual balances through May 2018 for prepaid expenses representing an increase of $19,474. The remaining pro forma months of 2018 are based on the corresponding 2017 monthly balances.

Adjustment H, shown on page 4, reflects the pro forma change in the beginning and end of the year averages of unamortized loss on reacquired debt balance based on the annual amortization, and the associated deferred income taxes as of December 31, 2017.

Adjustment I, shown on page 5, reflects the pro forma change in the beginning and end of the year averages of decommissioning of retired plant balance based on the annual amortization, and the associated deferred income taxes as of December 31, 2017. The annual amortization of $16,984 is an offset to the depreciation expense in Rule 38.5.165, Statement I.

Adjustment J, shown on page 6, reflects the annual amortization of the excess generation facility decommissioning balances as well as the reclassification of the remaining balance to the accumulated reserve, as discussed earlier in my testimony, and the associated deferred income taxes as of December 31, 2017.

As previously discussed, on April 1, 2017, Montana-Dakota redeemed all outstanding preferred stock. A call premium of $600,000 was incurred upon redemption of preferred stock. The call premium has been deferred on the Company's books. The Company is now proposing to include this regulatory asset in rate base and to amortize the balance over the 15-year life of the long-term debt. Therefore, this item has been reflected in the revenue requirement in a manner similar to the unamortized loss on debt as shown in Rule 38.5.143, Statement E, page 7 (Adjustment K).

Adjustment L, shown on page 8 is the average net provision for pensions and benefits and the associated deferred income taxes as of December 31, 2017, and has been included in the rate base in conformance with Order 5856b in Docket No. D95.7.90. The average net provision for pensions and benefits is currently an asset on the Company's books. The balance on the Company's books is based on the net position of the Company's contributions to the pensions trust account and the pensions expense recovered through the cost of service as a component of benefits expense. During the period beginning January 1, 2010 through December 31, 2017, Montana-Dakota has contributed $54.5 million to the pensions trust account based on the actuarially determined requirements. During that same time frame, the Company has recovered only $7.9 million from customers. The total Company balance of $44.3 million as of December 31, 2017 represents the net Company contribution related to pensions.

Adjustment M, shown on page 9 is the average net provision for injuries and damages and the associated deferred income taxes as of December 31, 2017, in conformance with Order 5856b in Docket No. D95.7.90.

The accumulated deferred income tax adjustments are summarized in Rule 38.5.169, Statement J, page 11, Adjustment N. The adjustment shows the increase to deferred taxes necessary to extend the average accumulated deferred tax balance to match the pro forma plant and accumulated reserve balances. The adjustment includes the deferred taxes associated with the unamortized loss on debt (Adjustment H), decommissioning of retired power plants (Adjustment I), generation facility decommissioning (Adjustment J), provision for pensions and benefits (Adjustment L), and provision for injuries and damages (Adjustment M). Liberalized depreciation, Thunder Spirit expansion, customer advances, full normalization, net negative salvage, excess deferred non-plant, PTC carryforward, and R&D tax credit carryforward are also shown on Adjustment N, page 11.

Adjustment P is the customer advances for construction reflecting a thirteenth-month average, with actual balances through May 2018 for an increase of $171,510 as shown in Rule 38.5.143, Statement E, page 10.

These are all the pro forma adjustments to revenue, expense, and rate base.

Q. What does Rule 38.5.190, Statement O show?

A. The charts and graphs contained in Rule 38.5.190, Statement O, Part A are the pictorial exhibits required by Commission rules.

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRJ-1)?

A. Exhibit No.____(TRJ-1) is identical to Rule 38.5.175, page 8. It shows the calculation of the revenue deficiency of $11,881,460 to be collected in the following manner based on the Company's proposal:

$379,618	Estimated 1/1/2019 TTA True Up
569,899	Estimated Base TTA True Up
2,380,077	Proposed to be collected through FPPA
8,551,866	Base rate increase
$11,881,460	

The revenue requirement above is based on the pro forma operating income, rate base, and the overall rate of return of 7.542 percent from Rule 38.5.146, Statement F, page 1.

<u>Electric Fuel and Purchased Power Cost Tracking Adjustment</u>

Q. Would you describe the adjustments to the electric fuel and power adjustment cost tracking adjustment proposed in this filing?

A. Yes. Montana-Dakota is proposing to incorporate changes in the fuel and purchased power cost tracking adjustment.

First, as discussed earlier, the Company is proposing to include sand expense in the fuel and purchased power cost tracking adjustment and to remove the existing sand expense from production operation and maintenance expense. This proposed change results in a shift in recovery from Production O&M expense to fuel and purchased power expense. Correspondingly, Adjustment No. 10, Rule 38.5.157, Statement G, page 10, reflects the removal of sand expense from Production O&M expense.

Second, as mentioned earlier in my testimony, the Company is proposing to include all expenses associated with the MISO and SPP Regional Transmission Organizations (RTO) markets in the fuel and purchased power cost tracking adjustment. The testimony of Mr. D. Neigum further describes the connectedness of the energy and transmission markets within the RTOs and the benefits that the transmission market affords the energy markets and why the Company is proposing to treat the charges for both markets within the fuel and purchased power cost tracking adjustment. This proposed changed would reflect the recovery of transmission service expense and revenue through the fuel and purchased power cost tracking adjustment. The following table reflects the per unit impact as a result of the proposed change:

	Primary	Secondary	Contract
With Transmission	$0.02895	$0.02858	$0.02685
Excluding Transmission	0.02523	0.02542	0.02456
Change	$0.00372	$0.00316	$0.00229

Montana-Dakota's proposal shifts the recovery of transmission service expense and RTO transmission service revenue from base rates to the fuel and purchased power cost tracking adjustment in a manner consistent with other components of the existing fuel and purchased power cost tracking adjustment.

Next, the Fort Peck energy costs have been allocated only to secondary service customers as all current Fort Peck customers are secondary service customers.

Lastly, Montana-Dakota proposes to remove Subsection 7 (c) in Rate 58 and Subsection 5 (c) in Rate 35. The over or under recovered Public Service Commission and Montana Consumer Counsel tax balance would be more appropriately recovered in a manner consistent with Montana-Dakota's Rate 88 - Gas Cost Tracking Adjustment. The unreflected fuel and purchased power cost tracking adjustment is updated annually and would include an adjustment to amortize the remaining balance over the following twelve month period. This proposal would eliminate a line on customers' bills reducing customer confusion regarding two separate line regarding tax recovery. In addition, the Commission approves the annual filing on an interim basis which would provide a more timely match between the expenses incurred and the revenue recovered.

Exhibit No. ___(TRJ-2) is the proposed Rate 35 and Rate 58 tariffs, also included in Appendix B.

Interim Revenue Requirement

Q. Would you please describe the derivation of the interim increase?

A. Yes. The interim increase has been developed in a separate set of Interim Statements pursuant to the Commission's rules regarding interim rate increase requests in general rate proceedings (Administrative Rules of Montana 38.5.505 and 38.5.506).

The derivation of the interim request follows the Commission approved methodology and consists of adjustments to revenue, expense, and rate base. The interim request is based on the capital structure and debt costs proposed by the Company and a return on equity of 9.25% percent – the mid-range of the return on equity referenced in the Commission's Order in Docket No. D2015.6.51 – resulting in an overall return of 7.012 percent. The pro forma adjustments to revenue and expense are listed in Rule 38.5.175, pages 2 through 3 and the adjustments to rate base are summarized on page 5.

The interim increase has been developed exclusive of Rate 56 - Electric Tax Tracking Adjustment revenue and pro forma direct Montana ad valorem tax expense to recognize that the Company expects to file a separate request which will update the true up portion of Rate 56 to be effective January 1, 2019.

Q. Would you describe the interim adjustments to operating revenues?

A. The interim adjustments to operating revenues are contained in Rule 38.5.164, Statement H, page 1.

Adjustment No. 1 is a decrease of $1,668,828 in retail sales revenue that is based on actual 2017 volumes and current rates reflecting the pro forma fuel and purchased power expense. As noted, the pro forma revenue is exclusive of the TTA revenue.

Adjustment No. 2 decreases revenue by $226,695 to reflect the elimination of sales for resale as these revenues are passed back to customers through the Fuel & Purchased Power Adjustment.

Adjustment No. 3 includes the adjustments to other operating revenues that reflect an overall decrease of $893,426. The pro forma interim adjustments have been computed consistently with the Company's rate increase filing.

Q. What interim adjustments were made to operation and maintenance expenses?

A. The interim adjustments to operation and maintenance expenses are summarized in Rule 38.5.156, Statement G, page 1 and contained in Rule 38.5.157, Statement G.

Adjustment No. 4 increases the cost of fuel and purchase power expense by $1,129,628 that reflects current MISO market pricing, normal outage schedules, Thunder Spirit wind facility expansion, and the Company proposing to reclassify sand expense from Production O&M expense and recover it through the same manner as the fuel and purchased power cost tracking adjustment. Adjustment No. 10 reflects the removal of sand expense from Production O&M expense. Adjustment No. 4 reflects a reduction of $275,777 related to RTO transmission service expense as well.

Q. Would you describe the other interim adjustments to O&M expense?

A. Adjustment No. 5 is a decrease of $45,528 for normalized labor expense as well as the addition of estimated labor for the Thunder Spirit expansion.

Adjustment No. 6 is an increase of $63,444 for benefits expense that was based on adjusting each type of benefit individually using current information and applying the percentage change to each type of benefit.

Adjustment No. 7 is a decrease of $148,036 for facility charge expense.

Adjustment No. 8 is an increase of $418,651 for subcontract labor expense that reflects increased maintenance agreements with Thunder Spirit and Glen Ullin Station (Ormat).

Adjustment No. 9 is an increase of $449,870 for Big Stone and Coyote expense that reflects current operations for 2018.

Adjustment No. 10 is a decrease of $109,254 for sand expense that is based on the Company’s proposal for removing sand expense from Production O&M expense and recover it through the fuel and purchased power cost tracking adjustment as mentioned earlier in Adjustment No. 4.

Adjustment No. 11 is a decrease of $526 for vehicles and work equipment expense that includes all expenses associated with the Company’s vehicles and equipment such as backhoes, skid steers, excavators, the costs of fuel, insurance, maintenance, and depreciation expense. The increase was based on pro form plant and the currently approved depreciation rates in Statement I. The depreciation component on these items are not charged to depreciation but rather are charged to a clearing account where they are then recorded in O&M expense as the vehicles or work equipment are used.

Adjustment No. 12 is a decrease of $1,293 for company consumption expense that is the electric and natural gas consumption in Company buildings. The electric component is projected to increase $2,247 and the natural gas component is projected to decrease $3,540 based on the decrease in normalized firm sales and average 2017 gas cost.

Adjustment No. 13 is an increase of $34,923 for uncollectible accounts expense that is based on the three-year average of net write-offs to pro forma sales and transportation revenues.

Adjustment No. 14 is a decrease of $9,380 for advertising expense that reflects the elimination of general promotional advertising expense and excludes informational and institutional advertising expense not directly applicable to Montana electric operations.

Adjustment No. 15 is an increase of $27,997 for insurance expense that reflects current levels for 2018. Property insurance was adjusted to include the Thunder Spirit expansion and self-insurance expense was adjusted to reflect a five-year average of claims and related expenses paid.

Adjustment No. 16 is an increase of $78,220 for software maintenance expense that is based on current and estimated levels of expense and implementation of new software.

Adjustment No. 17 is an increase of $8,337 for industry dues expense that reflects current 2018 levels and are directly assigned or allocated to Montana. In compliance with past orders, 40 percent of dues to the local Chambers of Commerce are excluded.

Adjustment No. 18 is a decrease of $47,460 for rent expense that reflects the elimination of a Lewis & Clark rental and a reduction of corporate expenses.

Adjustment No. 19 is an increase of $66,926 for annual easements expense that is based on the easement increases for Cedar Hills and Thunder Spirit, including the expansion at Thunder Spirit.

Lastly, adjustment No. 20 is a decrease of $104,393 for regulatory commission expense that reflects three-year amortization of ongoing regulatory commission expense, five-year amortization of electric and common depreciation study expense, and five-year amortization of decommissioning study expense.

Q. What interim adjustments were made to depreciation expense?

A. The interim adjustments to depreciation expense are summarized in Rule 38.5.165, Statement I, page 1.

Adjustment No. 21 shows the annual depreciation expense to the average pro forma level of plant in service excluding the Thunder Spirit expansion. The electric and common depreciation rates proposed in this filing are consistent with depreciation rates approved in the last electric rate case in Docket No. D2015.6.51. The depreciation rates are shown on Statement I, pages 3 through 7.

For the purposes of the interim rate request, the per books and pro forma expense and rate base treatment of the preferred stock redemption has been excluded from the Company's filing.

Adjustment No. 22 shows the annual depreciation expense of $904,907 for the Thunder Spirit expansion.

Q. What adjustments were made to taxes other than income?

A. The interim adjustments to taxes other than income are summarized in Rule 38.5.173, Statement K, page 1 and contained in Rule 38.5.174, Statement K.

Adjustment No. 23 is an overall decrease of $3,625,463 for ad valorem taxes that reflects Montana ad valorem taxes, allocated ad valorem taxes, and tribal ad valorem taxes. The direct Montana ad valorem taxes per books amount of $3,649,093 were eliminated for interim purposes as noted earlier in my testimony. The allocated ad valorem taxes increased $16,460 and was based on the change in the average allocated pro forma plant balances. Lastly, the tribal ad valorem taxes increased $7,170 to reflect a three-year average increase.

Adjustment No. 24 is a decrease of $2,993 for payroll taxes that is based on the ratio of payroll taxes to labor expense for 2017 applied to the pro forma labor expense.

Adjustment No. 25 is an increase of $49,607 for electric production taxes that reflects the pro forma load resources included in Adjustment No. 4, including the Thunder Spirit expansion.

Adjustment No. 26 is a decrease of $144,425 for Montana Consumer Counsel Tax and Public Service Commission taxes that are based on applying the tax rate, effective October 1, 2017, to the pro forma revenue and miscellaneous revenue.

Q. What adjustments were made to income taxes?

A. The interim adjustments to income taxes are summarized in Rule 38.5.169, Statement J, page 1.

Adjustment No. 27 is an increase of $231,633 for interest expense reflecting the pro forma rate base and cost of debt. Interest expense is deductible for tax purposes and calculated on the pro forma rate base using the weighted cost of debt.

Adjustment No. 28 is an increase of $6,740,741 for tax/book depreciation and an increase of $1,775,006 for deferred income taxes on plant additions, including the Thunder Spirit expansion.

Adjustment No. 29 is a decrease of $13,978 for elimination of preferred stock deduction due to redemption as explained in Ms. T. Nygard’s Direct Testimony.

Adjustment No. 30 is a decrease of $2,295,414 for pro forma adjustments to current income taxes on operating revenues and expenses.

Adjustment No. 31 is an increase of $735,505 for production tax credit (PTC) that was adjusted to reflect a credit of 2.4 cents per kWh of production for the energy produced at the Company's wind generating facilities, including incremental generation from the Thunder Spirit expansion and a reduction in generation for Diamond Willow as there were turbines that reached the ten years in service date and are no longer eligible to receive the production tax credit.

Adjustment No. 32 and Adjustment No. 34 are the adjustments to current and deferred income taxes to reflect the TCJA. As discussed earlier in my testimony, these adjustments reflect the reduction in the federal tax rate from 35 percent to 21 percent.

Adjustment No. 33 is the closing/filing and prior period adjustments for the current and deferred income taxes. Adjusted current and deferred income taxes match those calculated for Montana and conform to past Commission practices.

Adjustment No. 35 is the plant and non-plant excess deferred taxes shown on page 10 that resulted from the TCJA.

Q. What interim adjustments were made to rate base?

A. The interim adjustments to rate base are summarized in Rule 38.5.175, page 5.

Adjustment A is the annualization of the plant balances as shown in Rule 38.5.123, Statement C, pages 2 through 8. The increase totals $6,842,234.

Adjustment B is Montana's allocated plant additions for the Thunder Spirit expansion. This investment is $22,622,671 and has been annualized to reflect the plant additions as if they we in service the entire year.

Adjustment C is the accumulated reserve for depreciation on plant additions for $9,709,920 shown in Rule 38.5.133, Statement D, page 2, that reflects the average pro forma level to coincide with the average pro forma plant levels.

Adjustment D is the accumulated reserve for depreciation on Montana's allocated plant additions for the Thunder Spirit expansion of $904,907 reflecting an annualized addition and shown in Rule 38.5.165, Statement I, page 8.

The working capital adjustments are summarized in Rule 38.5.141, Statement E and were adjusted to reflect the following changes:

- Materials and supplies (Adjustment E) reflects a thirteen-month average, with actual balances through May 2018 for an increase of $32,381.

- Fuel stores (Adjustment F) reflects a thirteen-month average, with actual balances through May 2018 for a decrease of $20,537.
- Prepaid expenses (Adjustment G) reflects a thirteen-month average, with actual balances through May 2018 for an increase of $19,474.
- Unamortized loss on debt (Adjustment H) reflects a beginning and end of year average for a decrease of $71,359.
- Decommissioning of retired plants (Adjustment I) reflects a beginning and end of year average for an increase of $16,984.
- Generation facility decommissioning (Adjustment J) reflects an increase of $1,342,439.
- Provision for pensions and benefits (Adjustment L) reflects a beginning and end of year average for an increase of $726,659.
- Provision for injuries and damages (Adjustment M) reflects a beginning and end of year average for a decrease of $53,806.

The accumulated deferred income taxes adjustments are summarized in Rule 38.5.169, Statement J, page 11.

Adjustment N identifies the accumulated deferred income tax adjustments for unamortized loss on debt (Adjustment H), decommissioning of retired plants (Adjustment I), generation facility decommissioning (Adjustment J), provision for pensions and benefits (Adjustment L), and provision for injuries and damages (Adjustment M). Liberalized depreciation, Thunder Spirit expansion, customer advances, full normalization, net negative salvage, excess deferred non-plant, PTC carryforward, and R&D tax credit carryforward are also shown on Adjustment N, page 11.

Adjustment P is the customer advances for construction reflecting a thirteenth-month average with actual balances through May 2018 for an increase of $171,510 shown in Rule 38.5.143, Statement E, page 10.

These are all of the pro forma adjustments to revenue, expense, and rate base related to the interim request.

Q. What does Exhibit No.____(TRJ-3) show?

A. Exhibit No.____(TRJ-3) is identical to Interim Rule 38.5.175, page 6. It shows the calculation of the revenue deficiency of $4,596,243 that is based on the pro forma operating income, rate base, and the overall rate of return of 7.012 percent from Interim Rule 38.5.146, Statement F, page 1.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PRO FORMA OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$63,024,771	**$11,881,460**		$74,906,231
Sales for Resale	0			0
Other	5,691,993			5,691,993
Total Revenues	68,716,764	11,881,460		80,598,224
Operating Expenses				
Operation and Maintenance				
Fuel & Purchased Power	20,147,866			20,147,866
Other O&M	26,639,220			26,639,220
Total O&M	46,787,086			46,787,086
Depreciation	14,254,752			14,254,752
Taxes Other Than Income	5,660,817	34,456	2/	5,695,273
Current Income Taxes	(8,685,619)	3,119,612	2/	(5,566,007)
Deferred Income Taxes	3,493,280			3,493,280
Total Expenses	61,510,316	3,154,068		64,664,384
Operating Income	$7,206,448	$8,727,392		$15,933,840
Rate Base	$211,268,096			$211,268,096
Rate of Return	**3.411%**			**7.542%**

1/ See Rule 38.5.175, page 6 and 7.
2/ Reflects taxes at 26.3325% after deducting Consumer Counsel tax of 0.046% and PSC tax of 0.244%.

Exhibit No.__(TRJ-2)

AVAILABILITY:

For the Denbury Onshore LLC accounts designated in the Electric Service Agreement dated June 28, 2017.

RATE:

Basic Service Charge:	$250.00 per month
Demand Charge:	
October – May	$ 8.50 per Kw
June – September	$10.00 per Kw
Energy Charge:	2.243¢ per Kwh
Base Fuel and Purchased Power:	2.685¢ per Kwh

MINIMUM BILL:

Basic Service Charge plus Demand Charge.

PAYMENT:

Bills will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100 or any amendments or alterations thereto.

ADJUSTMENT CLAUSES:

Bills are subject to the following adjustments as provided in the referenced rates, or any amendments or alterations thereto:

- Electric Universal System Benefits Charge Rate 55
- Electric Tax Tracking Adjustment Rate 56

DETERMINATION OF BILLING DEMAND:

The demand in kilowatts for billing purposes shall be the greater of the maximum 15 minute measured demand in the current month or 50 Kw. Demands will be determined to the nearest one-tenth kilowatt.

POWER FACTOR CLAUSE:

Montana-Dakota reserves the right to require Denbury Onshore LLC to install adequate equipment so that at all times it can operate its facilities to maintain a power factor between 90% lagging and 90% leading. If Denbury Onshore LLC operates outside this range, the maximum 15 minute integrated reactive kilovolt amperes in excess of 50% of the maximum 15 minute integrated kilowatt demand for the same month will be billed at $3.35 per Kvar of such excess demand.

GENERAL TERMS AND CONDITIONS:

The foregoing schedule is subject to Rates 100-131 and any amendments or alterations thereto or additional rules and regulations promulgated by Montana-Dakota under the laws of the state.

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT:

The following sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment for Contact Service Rate 35. It specifies the procedure to be utilized to adjust the rates for electricity sold in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in the net transmission service charges from regional transmission organizations (RTO); (c) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (d) amortization of the Unreflected Fuel Cost Account as allocated to Contract Service Rate 35.

1. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

   Unless otherwise ordered by the Commission, the effective date of the Fuel and Power Cost Tracking Adjustment and amortization of the Unreflected Fuel Cost Account shall be service rendered on and after January 1 each year.

2. FUEL AND POWER COST TRACKING ADJUSTMENT:

   a. The Fuel and Power Cost Tracking Adjustment shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.685¢ per Kwh as established in the most recent general rate case.

b. The cost of fuel and purchased power shall be calculated separately for Rate 35, and shall be the sum of the following estimated costs for the annual period the adjustment shall be in effect, as allocated to Montana and to Contract Service Rate 35, taking into account applicable line losses:
   1. The cost of fossil and other fuels and sand and reagents as recorded in Account Nos. 501, 502 and 547.
   2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account 555.
   3. The cost of electric transmission delivery services linked to the utility's load serving obligation and associated with participation in regional transmission organizations as recorded in Account Nos. 560, 561, 565 and 928 offset by corresponding revenues received from regional transmission organizations as recorded in Account No. 456.
   4. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the year is the sum of 2(b) above divided by projected Contract Service Rate 35 sales volumes for the period the adjustment will be in effect.

d. The Annual Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 2(b) multiplied by ninety (90) percent.

3. UNREFLECTED FUEL COST ADJUSTMENT:
   Contract Service Rate 35 shall be subject to an Unreflected Fuel Cost Adjustment to be effective on January 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected Fuel

Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

4. UNREFLECTED FUEL COST ACCOUNT:
   a. Items to be included in the Unreflected Fuel Cost Account are:
      1. Amounts under recovered or over recovered for fuel and purchased power each month as calculated in accordance with Subsection 4(b).
      2. Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

   b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 4(a)(1) and (2) shall be calculated as follows:
      1. Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power.
      2. Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.
      3. The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in an Unreflected Fuel Cost Account for Contract Service Rate 35.
      4. Carrying charges or credits at a rate equal to the overall rate of return established in the most recent general rate case.

   c. Reduction of Amounts in the Unreflected Fuel Cost Account:
      1. The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 4) under Contract Service Rate 35. The Account shall be increased in the event the adjustment is a negative amount. The amount amortized shall be applied pro rata between the Unrecovered Fuel Cost Account and the interest balance.

5. TIME AND MANNER OF FILING:
   a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 6 identifying the amount of the adjustment.

   b. Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

6. EFFECTIVE ADJUSTMENT:

Base Fuel	2.685¢
Fuel and Power Cost Adjustment	____________
Total Adjustment per Kwh	

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

1. APPLICABILITY:
This rate schedule sets forth the procedure to be used in calculating the Electric Fuel and Purchased Power Cost (Fuel and Power Cost) Tracking Adjustment. It specifies the procedure to be utilized to adjust the rates for electricity sold under Montana-Dakota's rate schedules in the state of Montana, excluding Contract Service Rate 35, in order to reflect: (a) changes in Montana-Dakota's average cost of fuel and purchased power; (b) changes in the net transmission service charges from regional transmission organizations (RTO) (c) changes in Montana-Dakota's electric wholesale sales revenues and Renewable Energy Credit revenues; and (d) amortization of the Unreflected Fuel Cost Account.

2. EFFECTIVE DATE AND LIMITATION ON ADJUSTMENTS:

a. Unless otherwise ordered by the Commission, the effective dates of the Fuel and Power Cost tracking adjustment shall be service rendered on and after the first day of each month. The effective date of the adjustment for amortization of the Unreflected Fuel Cost Account shall be July 1 of each year.

b. Montana-Dakota shall file an adjustment to reflect changes in its average cost of electric supply only when the amount of change in such adjustment is at least .001 cents per Kwh. The tracking adjustment to be effective July 1 shall be filed each year, regardless of the amount of the change.

3. MINIMUM FILING REQUIREMENTS:
Montana-Dakota's filing to implement the Fuel and Power Cost Tracking Adjustment effective July 1 of each year shall include the following:

a. Fuel and purchased power costs and transmission costs and revenues by month by source, with annual totals;

b. Generation and purchases (Mwh) by month by supply source, with annual totals;

c. Total Montana-Dakota sales by major customer class by month with annual totals and;

d. Montana-Dakota sales by major customer class by jurisdiction by month, with annual totals.

4. FUEL AND POWER COST TRACKING ADJUSTMENT:

a. The monthly Fuel and Power Cost Tracking Adjustment shall be calculated separately for primary voltage and secondary service customers and shall reflect ninety (90) percent of the changes in Montana-Dakota's cost of fuel and purchased power as compared to the cost of fuel and purchased power approved in its base rates plus the annual Unreflected Fuel Cost Adjustment. The base fuel cost shall be 2.895¢ per Kwh for primary service and 2.858¢ per Kwh for secondary service as established in the most recent general rate case.

b. The cost of fuel and purchased power shall be calculated separately for primary service customers and secondary service customers, and shall be the sum of the following costs for the most recent four month period, as allocated to Montana and to the primary and secondary customer classes:

   1. The cost of fossil and other fuels and sand and regents as recorded in Account Nos. 501, 502 and 547.

   2. The net cost of purchases and costs linked to the utility's load serving obligation associated with participation in wholesale electric energy and capacity markets as recorded in Account No. 555.

   3. The cost of electric transmission delivery services linked to the utility's load serving obligation and associated with participation in regional transmission organizations as recorded in Account Nos. 560, 561, 565 and 928 offset by corresponding revenues received from regional transmission organizations as recorded in Account No. 456.

4. Less electric wholesale sales revenues and Renewable Energy Credit revenues.

c. The cost per Kwh for the month is the sum of 4(b) above divided by retail sales volumes for the most recent four month period for the primary and secondary service classes excluding Contract Service Rate 35.

d. The Fuel and Power Cost Tracking Adjustment shall be the difference between the base cost of fuel and purchased power and the calculated cost in 4(c) multiplied by ninety (90) percent.

The applicable Fuel and Power Cost Tracking Adjustment shall be applied to each of Montana-Dakota's rate schedules except Contract Service Rate 35, recognizing differences among customer classes consistent with the cost of fuel and purchased power included in the applicable class sales rate.

5. UNREFLECTED FUEL COST ADJUSTMENT:

All sales rate schedules shall be subject to an Unreflected Fuel Cost Adjustment to be effective on July 1 of each year. The Unreflected Fuel Cost Adjustment per Kwh shall reflect amortization of the applicable balance in the Unreflected Fuel Cost Account calculated by dividing the applicable balance by the estimated Kwh sales for the twelve months following the effective date of the adjustment.

6. UNREFLECTED FUEL COST ACCOUNT:

a. Items to be included in the applicable Unreflected Fuel Cost Account, are:

(1) Amounts under recovered or over recovered for fuel and purchased power, as calculated in accordance with Subsection 6(b) each month.

(2) Refunds received with respect to fuel and purchased power. Such refunds received shall be credited to the Unreflected Fuel Cost Account.

b. The amount to be included in the Unreflected Fuel Cost Account in order to reflect the items specified in Subsection 6(a) (1) and (2) shall be calculated as follows:

   (1) Montana-Dakota shall first determine each month the cost for that month's fuel and purchased power as specified in Subsection 4.

   (2) Montana-Dakota shall then subtract from each month's cost the cost of fuel and purchased power included in rates for that month.

   (3) The resulting difference (which may be positive or negative) shall be multiplied by ninety (90) percent and be reflected in the Unreflected Fuel Cost Account for each applicable rate schedule.

c. Reduction of Amounts in the Unreflected Fuel Cost Account:

   (1) The amounts in the Unreflected Fuel Cost Account shall be decreased each month by the amount of the Unreflected Fuel Cost adjustment included in rates for that month (as calculated in Subsection 6) under each applicable rate schedule. The Account shall be increased in the event the adjustment is a negative amount.

7. TIME AND MANNER OF FILING:

a. Each filing by Montana-Dakota shall be made by means of a revised fuel and power cost schedule provided in Subsection 8 identifying the amount of the adjustment.

b. Each filing shall be accompanied by detailed computations which clearly show the derivation of the relevant amounts.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of Montana
Electric Rate Schedule

FUEL AND PURCHASED POWER COST TRACKING ADJUSTMENT Rate 58

8. FUEL AND POWER COST ADJUSTMENT :

	Primary	Secondary
Base Fuel	2.895¢	2.858¢
Fuel and Power Cost Adjustment		
Total FPPA per Kwh		

Issued: September 28, 2018

By: Tamie A. Aberle
Director - Regulatory Affairs

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT ON PRO FORMA ADJUSTMENTS
ELECTRIC UTILITY - MONTANA

Adjustment	Adjustment Description	Adjustment Amount	Income Tax Amount	Income Effect	Revenue Requirement
Revenue Deficiency - Per books 2017					**$5,740,156**
	Income Statement Adjustments				
1	Pro Forma at Current Rates	$1,448,569	$381,444	($1,067,125)	($1,452,782)
2	Sales for Resale	(226,695)	(59,694)	167,001	227,355
3	Other Revenue	(3,350)	(882)	2,468	3,360
3	Transmission Service Revenue	(887,052)	(233,583)	653,469	889,631
4	Fuel and Purchased Power	1,129,628	(297,459)	832,169	1,132,913
4	RTO Transmission Service Expense	(275,777)	72,619	(203,158)	(276,579)
5	Labor	(45,528)	11,989	(33,539)	(45,660)
6	Benefits	63,444	(16,706)	46,738	63,629
7	Facility Charge	(148,036)	38,981	(109,055)	(148,467)
8	Subcontract Labor	418,651	(110,241)	308,410	419,869
9	Big Stone/Coyote	449,870	(118,462)	331,408	451,178
10	Sand	(109,254)	28,769	(80,485)	(109,572)
11	Vehicles & Work Equipment	71,493	(18,826)	52,667	71,701
12	Company Consumption	(1,293)	340	(953)	(1,297)
13	Uncollectible Accounts	44,275	(11,659)	32,616	44,403
14	Advertising	(9,380)	2,470	(6,910)	(9,407)
15	Insurance	27,997	(7,372)	20,625	28,079
16	Software Maintenance	78,220	(20,597)	57,623	78,448
17	Industry Dues	8,337	(2,195)	6,142	8,362
18	Rent Expense	(47,460)	12,497	(34,963)	(47,599)
19	Annual Easements	66,926	(17,623)	49,303	67,121
20	Regulatory Commission Expense	52,140	(13,730)	38,410	52,291
21	Depreciation Expense	2,783,770	(733,036)	2,050,734	2,791,865
21	Decommissioning Expense	1,393,549	(366,956)	1,026,593	1,397,602
21	Pref. Stock Redemption Amort.	93,872	(24,719)	69,153	94,145
22	Thunder Spirit Expansion	904,907	(238,285)	666,622	907,538
23	Ad Valorem	441,451	(116,245)	325,206	442,735
24	Payroll Taxes	(2,993)	788	(2,205)	(3,002)
25	Production Taxes	49,607	(13,063)	36,544	49,751
26	MCC and PSC Taxes	(135,376)	35,648	(99,728)	(135,769)
27	Interest Annualization	375,205	(98,801)	(98,801)	(134,507)
28	Tax Depreciation on Plant Additions	1,067,721	(281,158)	(281,158)	(382,768)
29	Preferred Stock Deduct/Amortization	(13,978)	3,681	3,681	5,011
30	Current Income Taxes on Pro Forma Adj.	(2,212,066)	2,212,066	0	
31	Production Tax Credits	(735,505)		(735,505)	(1,001,315)
32	2017 Current Taxes - Adjusted for TCJA	1,671,805		1,671,805	2,275,992
33	Closing/Filing and Prior Period-Current	260,289		260,289	354,357
28	Def. Tax-Plant Additions-Book/Tax Diff.	281,158		281,158	382,768
34	2017 Deferred Taxes - Adjusted for TCJA	(2,192,872)		(2,192,872)	(2,985,372)
35	Plant Excess Deferred Taxes - ARAM	(438,305)		(438,305)	(596,708)
35	Non-plant Excess Deferred Taxes - Amort.	17,187		17,187	23,398
33	Closing/Filing and Prior Period-Deferred	(257,629)		(257,629)	(350,736)
Total Income Statement Adjustments		**($3,365,630)**		**($3,365,630)**	**$4,581,962**

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENT ON PRO FORMA ADJUSTMENTS
ELECTRIC UTILITY - MONTANA

Adjustment	Adjustment Description	Adjustment Amount	Income Tax Amount	Income Effect	Revenue Requirement
	Rate Base Adjustments				
Plant in Service					
A	Plant Additions	$13,911,910			$1,428,428
B	Thunder Spirit Expansion-Plant Adds	22,622,671			2,322,820
Accumulated Reserve					
C	Pro Forma Depreciation	11,033,841			(1,132,918)
D	Thunder Spirit Expansion-Accum Reserve	904,907			(92,913)
J	Generation Facility Decommissioning	1,666,037			(171,063)
Working Capital					
E	Materials and Supplies	32,381			3,325
F	Fuel Stores	(20,537)			(2,109)
G	Prepayments	19,474			2,000
H	Unamortized Loss on Debt	(71,359)			(7,327)
I	Decommissioning of Retired Plants	16,984			1,744
J	Generation Facility Decommissioning	2,982,921			306,276
K	Unamort. Redemption Cost of Pref. Stock	41,069			4,217
L	Provision for Pension and Benefits	726,659			74,611
M	Provision for Injuries and Damages	(53,806)			(5,525)
Accumulated Deferred Income Taxes					
N	Plant Additions	3,122,878			(320,647)
O	Thunder Spirit Expansion	110,388			(11,334)
N	Customer Advances	95,849			(9,841)
N	Full Normalization	5,377			(552)
N	Net Negative Salvage	(30,652)			3,147
N	Unamortized Loss on Debt	(73,762)			7,574
N	Decommissioning of Retired Plants	9,646			(990)
N	Generation Facility Decommissioning	1,174,898			(120,635)
N	Pensions and Benefits	(111,493)			11,448
N	Injuries and Damages	(17,463)			1,793
N	Excess Deferreds - Plant	(334,192)			34,314
N	PTC Carryforward	2,218,019			(227,739)
N	R&D Tax Credit Carryfrwrd	10,325			(1,060)
Customer Advances					
P	Customer Advances for Construction	171,510			(17,610)
Total Rate Base Adjustments		**$20,252,254**			**$2,079,434**
Cost of Capital - Lower Cost of Debt / Capital Allocation					**($520,092)**
Revenue Deficiency - Pro Forma 2018					**$11,881,460**

MONTANA-DAKOTA UTILITIES CO.
INTERIM OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$59,907,374	**$4,596,243**		$64,503,617
Sales for Resale	0			0
Other	5,688,969			5,688,969
Total Revenues	65,596,343	4,596,243		70,192,586
Operating Expenses				
Operation and Maintenance				
Fuel & Purchased Power	20,147,866			20,147,866
Other O&M	26,401,316			26,401,316
Total O&M	46,549,182			46,549,182
Depreciation	10,235,270			10,235,270
Taxes Other Than Income	1,584,854	13,329	2/	1,598,183
Current Income Taxes	(8,768,967)	1,206,796	2/	(7,562,171)
Deferred Income Taxes	4,987,128			4,987,128
Total Expenses	54,587,467	1,220,125		55,807,592
Operating Income	$11,008,876	$3,376,118		$14,384,994
Rate Base	$205,148,238			$205,148,238
Rate of Return	**5.366%**			**7.012%**

1/ See Rule 38.5.175, page 1 and 4.
2/ Reflects taxes at 26.3325% after deducting Consumer Counsel tax of 0.046% and PSC tax of 0.244%.

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___
Direct Testimony
of
Jordan R. Hatzenbuhler

Q. Would you please state your name and business address?

A. Yes. My name is Jordan R. Hatzenbuhler, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am a Senior Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as a Senior Regulatory Analyst?

A. I am responsible for the preparation of class cost of service studies, and the development of rate design and I assist in preparing various filings required by state commissions.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of North Dakota in Grand Forks, North Dakota with a Bachelor of Accountancy degree, and I am a Certified Public Accountant (CPA). I started my career with PricewaterhouseCoopers as an audit associate and have since held multiple positions within MDU Resources Group prior to starting in my current role in 2015, including: Internal Auditor, Investor Relations Financial Analyst, and Senior Financial Reporting and Planning Analyst.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the results of the embedded class cost of service study and to present the effect of the proposed revenue requirement, as identified by Mr. Jacobson in his direct testimony, on each of the Company's electric rates, including how the distribution of the revenue requirement was made among the various classes of customers served.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and before the Public Service Commissions of North Dakota and Wyoming.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement H, page 8, Statement L, Statement M, Statement O, Part B, Exhibit No. ___ (JRH-1) and Exhibit No. ___ (JRH-2). I also sponsor Statement H, page 5 and Statement M of the Interim Application.

<u>Embedded Class Cost of Service Study</u>

Q. Would you please explain the embedded class cost of service study contained in Statement L?

A. Yes. Statement L, pages 1 through 11 provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the Pro Forma rate of return of 7.542 percent were to be earned for the demand, energy and customer cost components of each rate schedule.

The Cost of Service by Component report includes adjustments to the total cost of service required from each rate class for Transmission Expense Recovery and a Tax Tracking Adjustment. This is done to recognize that the dollars associated with these two adjustments are not proposed to be collected through base rates and to remove their impact from the unit cost computations. As is supported by Mr. Neigum and discussed by Mr. Jacobson, Transmission Services Expenses are proposed to be collected through Rate 58 - Fuel and Purchased Power Cost Tracking Adjustment (F&PP). The Tax Tracking adjustment reflects the amounts that will be collected through the Rate 56 - Electric Tax Tracking Adjustment (Tax Tracker).

A summary of the results by the major rate classifications, Residential, Small General Service, Large General Service, Municipal Pumping and Lighting is provided on page 1 of Statement L, Schedule L-1. Statement L, Schedule L-2, pages 1 through 121 is a report of the rate base, income statement and Pro Forma adjustments as allocated to each rate schedule. The allocation factor applied to the total Montana electric amount is shown on each line item and allocation factors used to allocate the total Montana electric amount to each class and cost component as referenced are provided in Statement L, Schedule L-3.

The embedded class cost of service study is based on the results for Montana electric operations for the 12 months ended December 31, 2017 as adjusted to reflect the Pro Forma adjustments as sponsored by Mr. Jacobson.

Q. What were the results of the embedded class cost of service study?

A. The overall Montana electric rate of return based on the actual results for the 12 months ending December 31, 2017 adjusted for known and measurable changes is 3.411 percent. The returns by customer class are as shown below:

Customer Class	ROR
Residential Service	1.5%
Small General Service	2.8%
Large General Service	4.9%
Municipal Pumping	1.2%
Lighting	1.1%
Total Montana Electric	**3.4%**

Q How did you determine what costs should be assigned to each customer class?

A. The starting point was classifying the functionalized costs by FERC account for all rate base and income statement items as demand, energy or customer related based on the component of service being provided. Demand-related costs are costs that vary with the Kw demand imposed by the customer, energy-related costs are costs that vary with the energy or Kwh the customer uses and customer-related costs are fixed costs driven by the number of customers served.

Next the plant, expense and revenue items that were identified as directly related to a specific class of customers were directly assigned to the appropriate class. Finally, the remaining costs were allocated using the various allocation factors shown in Statement L, Schedule L-3, on the basis of cost responsibility.

Q. Would you please provide an overview of the allocation process including the rationale underlying the choice of allocation factors?

A. Yes. I will start with the plant in service items on the rate base schedule starting on Schedule L-2, Page 1. The plant allocation serves as the basis for allocating many of the other rate base items. The investment in production related plant items was allocated on an average and excess demand (AED) allocator to account for the contribution of each class based on a combination of the class' average demand and non-coincident peak demand. The AED factor is comprised of the sum of the average demand of each class and the difference between the total system peak demand and the average demand as allocated to each class based on the non-coincident demand in excess of the average demand. The production investment related to the Company's wind facilities was allocated based 80 percent on the energy allocation factor (Factor No.1) and 20 percent on the average and excess demand allocator (Factor No. 2) to reflect the fact the wind facilities are primarily an energy resource. The investment in transmission plant related items was also allocated on the AED factor. Production and transmission plant investments were allocated in this manner in the class studies filed in each of the Company's last four electric cases filed in Montana.

Turning now to the distribution plant investment; each distribution plant account is analyzed and allocated based on the cause for the investment. Station equipment and the associated land and land rights are allocated on the non-coincident peak demand of each class, representing the maximum demand on the system. The next set of plant items - Poles, Towers & Fixtures; Overhead Conductors & Devices; Underground Conduit & Devices were classified as customer and demand related based on an analysis of the minimum and normal system design for a typical distribution system, with the minimum system representing the percentage of the plant accounts assigned to the customer component, and the remainder classified as demand related. Based on this analysis, the minimum investment necessary to connect a customer was determined to be 80 percent of Account 364 (Poles, Towers & Fixtures); Account 365 (Overhead Conductors) and Accounts 366 and 367 (Underground Conduit and Underground Conductors and Devices). The amounts classified as customer related were then allocated to each rate class based on the number of customers served in each rate class (excluding Contract Service Rate 35), or Factor No. 8.1. Contract Service Rate 35 is excluded from this allocator as service to customers under this schedule is provided at the substation level. The amount classified as demand related was allocated to each rate class based on the maximum demand of each rate class (Non-coincident peak Factor No. 4.1). The investment in Line Transformers was also classified as customer and demand related. The percentage assigned to the customer component was determined based on the minimum intercept method which seeks to identify the portion of the transformer investment associated with a hypothetical no-load condition. Based on an analysis of the type and size of transformers, representing the minimum equipment necessary to provide service to secondary system customers, the zero intercept was determined to be $1,601. Applying this amount to the number of transformers resulted in a customer component of 70 percent with the remaining 30 percent classified as demand related. The classified costs were allocated on weighted customer transformers and the non-coincident secondary demand factor accordingly.

The four remaining distribution accounts; Services, Meters, Installation on Customer Premises and Street Light & Signal System are all related solely to a customer connection and were classified as customer related. Services were allocated to the rate classes based on Factor 10 representing services weighted by customer class derived by comparing the installed cost per service for each rate class to the cost necessary to serve Residential Rate 10 customers. The weights were then applied to the number of customers in each rate class. The same process was used to fashion an allocation based on weighted meter costs (Factor No. 6) for allocating the embedded investment in meters. The investment in Installation on Customer Premises was directly assigned to Outdoor Lighting and the investment in Street Light & Signal Systems was directly assigned to Municipal Lighting. The allocation of the remainder of the rate base items is self-explanatory with the allocation factor noted for each line item.

Q. Would you please continue your discussion of the embedded class cost of service study with an explanation of the income statement items in the study?

A. Yes. The allocation of the income statement items starts on Schedule L-2, Page 3 with the allocation of revenues. As shown, revenues are primarily directly assigned based on the revenues produced by each rate class. The other revenues are allocated based on the source of the revenue item. Transmission service revenue is allocated based on the revenues that would be collected from each class assuming the proposed treatment of transmission services revenues and expenses is adopted. Each item is shown along with the allocation factor applied. Operation and maintenance expenses consisting of the cost of fuel, purchased power costs, transmission, distribution and administrative and general expenses are shown starting at Schedule L-2, page 4. The production expenses are classified as demand and energy related with the fuel, purchased power and variable production expenses classified as energy and allocated based on the energy requirements of each class. Transmission service expense is allocated in the same manner that transmission service revenue is allocated. The other production expenses and purchased capacity costs are classified as demand costs and allocated on the same demand allocator used to allocate production plant costs. Transmission operation and maintenance costs are also classified as demand related and allocated on the average and excess demand allocator (Factor No. 2). The remaining operation and maintenance expenses are allocated based on cost causation and typically follow the plant investment previously described in the rate base section. The remainder of the income statement reflects the allocation of depreciation expense, taxes other than income and income taxes as denoted by each line item. Finally, the pro forma adjustments as discussed by Mr. Jacobson, are allocated beginning at Schedule L-2, Page 7. Again, the allocation primarily follows the corresponding plant or expense item previously allocated. The allocation of costs to each rate schedule is presented in the same format as described above.

Q. You mentioned the allocation of Transmission Services Revenues and Expenses specifically, could you provide further clarification as to how those amounts are being handled?

A. As is discussed in Mr. Jacobson's testimony, the Company is proposing to recover Regional Transmission Organization associated transmission service expense net of related revenues through the F&PP rate. The embedded study reflects this change and allocates the transmission services expenses and revenues and corresponding pro forma adjustments based on the F&PP revenues that occur when applying the revised F&PP rates, as sponsored in Mr. Jacobson's testimony, to the pro forma volumes for each class.

Q. For what purpose has the embedded class cost of service study been used in this case?

A. The study results have been used for the purpose of analyzing the various components comprising the total rate applicable to each customer class. The embedded cost study was also utilized in the development of certain items in the marginal cost study.

Q. Has the Company also prepared a marginal class cost of service study?

A. Yes, Ralph Zarumba, of Concentric Advisors has prepared and sponsored a marginal class cost of service study on behalf of the Company.

Q. Have you prepared a reconciliation of the embedded revenue requirement to the marginal cost study?

A. Yes, as shown in the table below, the system level marginal costs are approximately 8.7 percent higher than the embedded cost revenue requirement.

Rate Class	Embedded COS	Marginal COS	Marginal vs. Embedded
Residential Rate 10	$23,088,690	$34,310,275	48.6%
Small General Rate 20	12,137,076	14,728,918	21.4%
Irrigation Rate 25	1,184,661	1,249,771	5.5%
Large General Rate 30 - Primary	6,430,999	5,297,736	-17.6%
Large General Rate 30 - Secondary	14,159,750	11,135,503	-21.4%
Large General TOD Rate 31	1,251,739	1,019,411	-18.6%
Large General Space Heat Rate 32	154,616	135,084	-12.6%
Large General Contract Rate 35	14,789,143	12,336,707	-16.6%
Municipal Pumping Rate 48	722,571	697,093	-3.5%
Municipal Lighting Rate 41	378,951	290,721	-23.3%
Outdoor Lighting Rate 52	608,035	244,961	-59.7%
	$74,906,231	$81,446,180	8.7%

Therefore, reconciliation between the marginal costs and embedded costs is necessary in order to utilize the marginal cost study. The reconciliation is shown on Statement M, Page 3. The results are also graphically presented in Statement O, Part B, pages 1 through 5.

Q. How do total marginal costs compare to total embedded costs?

A. The results of the study show that the system level marginal costs are approximately 8.7 percent higher than the embedded cost revenue requirement. At the customer rate class level, the differences range from being 49 percent greater than embedded costs to 60 percent lower than embedded costs.

Q. How is the marginal cost study used in Montana-Dakota's filing?

A. The marginal cost study is provided in compliance with the ARM 38.5.176. The study is not used directly to identify the revenue requirement but has informational value related to the allocation of revenues and development of rate design. Marginal costs can provide a cost signal that guides the efficient consumption of resources. As such, the marginal cost analysis is one consideration in the decision on how to allocate costs to the different customer classes and to recover those costs through rate design.

Revenue Allocation and Rate Design

Q. What is the total revenue effect of the proposed electric rate changes?

A. The proposed interim rates will produce additional revenues of $4,596,161 or an increase of 7.3 percent based on the interim level of test period sales, while the final proposed rates will produce additional revenues of $11,882,128 or an increase of 18.9 percent annually based on pro forma electric consumption and total revenues. Exhibit No.___(JRH-1) represents summaries by rate classification of the proposed interim and final revenue increase on pages 1 and 2, respectively. The exhibit shows the rate class along with the revenues calculated under the present and proposed rates. The amount and percentage increase are also shown for the proposed revenue increase. A pictorial representation of the proposed revenue increase is set forth on Part B, Page 17 of Statement O.

Q. How was the proposed interim revenue requirement apportioned among the customer classes?

A. The interim revenue requirement of $4,596,243 was applied on an equal percentage basis to all rate schedules. The Company is proposing to charge the interim increase of 7.29 percent as an equal percentage applicable to all rate schedules. The interim amount will be billed as a separate line item on the bill which will provide the ability for the Company to track the interim revenues collected from each customer. The calculations supporting the application of the interim increase to each class are provided in Statement M attached to the Application for Interim Increase in Electric Rates. The proposed interim rate schedules are provided in Appendix A to the Interim Application. As shown, the tariffs prescribe the interim increase as 11.560 percent of the amount billed under the basic service charge, energy, and demand components where applicable. Exhibit No. ___ (JRH-1), page 1 shows the interim increase applied to each of the rate classes.

Q. What methodology did you use to apportion the proposed rate increase among the customer classes in this case?

A. In designing the proposed rates to reflect the additional revenue requirement I first considered the results of the embedded class cost of service study, which provided the increase required from each class to produce the overall rate of return of 7.542 percent as shown on the Cost by Component report provided in Statement L, pages 1 through 11 and as summarized on Statement M, page 2. The embedded study provided in Statement L reflects the revenue requirement to be recovered through retail rates as shown on Statement M, page 2 resulting in a required revenue increase of $11,881,460. As shown here, $949,529 of the revenue increase is proposed to be recovered through the Tax Tracker and $2,379,519 of the increase is proposed to be recovered through F&PP, leaving a remainder of $8,552,412 designed to be collected through base rates representing a 14.28% overall increase. The required percentage increase to base rates for each class is shown and varies greatly from class to class; from a slight decrease for large general secondary to an increase of over 100% for small general irrigation.

Due to the magnitude of the overall increase, I initially considered applying an across the board increase. However, doing so substantially over-burdens the large general secondary and contract services classes in order to maintain the existing subsidization of primarily the residential, irrigation and outdoor lighting classes to an extent I did not find reasonable. In an effort to move under-performing classes towards cost of service and reduce the excess burden placed on certain classes, some mitigation was required.

To achieve this goal, the following apportionment was developed and deemed a reasonable compromise between an across the board increase and a wholesale move towards cost of service based rates. First, a max increase was set at 1.25 times the overall increase or 17.8451 percent. This increase was applied to all rate classes that the cost study indicated required at least that great of an increase to achieve cost of service. The residential, small general irrigation, large general primary, large general space heating, municipal lighting, municipal pumping and outdoor lighting rates were all applied the max increase. Next, small general secondary and large general time-of-day rates were applied the overall increase of 14.2761 percent. Finally, the remainder of the increase was assigned to the large general secondary and contract rates resulting in an increase of 11.0011 percent for these two classes.

Q. What is the proposed final increase by class of customer?

A. The proposed overall increase to each of the customer classes - inclusive of the amounts to be recovered through base rates, F&PP rates, and the Tax Tracker - is shown below:

Customer Class	Revenue Increase	% Increase
Residential Service	$3,928,950	22.0 %
Small General Service	2,049,230	18.8 %
Large General Service	5,635,858	17.1 %
Municipal Pumping	123,429	22.8 %
Lighting	144,661	21.5 %
Total Montana Electric	**$11,882,128**	**18.9 %**

Q. Would you please explain Exhibit No.____(JRH-2)?

Yes. Exhibit No.___(JRH-2), page 1 depicts a bill comparison based on typical monthly consumption levels for an annual period for Residential customers reflecting the proposed interim rates that results in an average monthly increase of approximately $5.83. Exhibit No.___(JRH-2), page 2 depicts the same comparison reflecting final proposed rates. As shown in the comparison, the proposed rate structure will result in an average increase of approximately $16.23 per month for the typical residential customer using 767 kwh on an annual basis.

Q. Would you please describe the rate form you are proposing for each rate schedule and how you propose to collect the allocated final increase from each of the rate schedules?

A. Yes. I will describe each rate schedule starting with Residential Service Rate 10. The Basic Service Charge was increased to $0.25 per day or $7.60 per month, an increase of $2.43 per month from the present rate. This proposed charge is well below the customer component supported in the embedded class study of $23.09 as shown on Statement L, page 1 or the marginal customer cost component of $85.36 monthly as provided by Mr. Zarumba on Table 23 of Exhibit No. ___(RZ-2). The proposed Basic Service Charge provides a balance between reflecting the true fixed costs of serving each customer and recognizing customer impacts. The energy charges for the residential rate schedule were determined by reducing the total revenue responsibility for the class (including the allocated revenue increase) by the revenues to be collected under the proposed Basic Service Charge, the seasonal differential and the pro forma F&PP component for secondary service. The revenues remaining to be collected were divided by the pro forma Rate 10 Kwh sales to determine the cost per Kwh required to be collected through the energy component.

The process described above for the calculation of the proposed Residential Rate 10 schedule was used to determine the rate components for each of the other rate schedules, that is, the first step was to establish the Basic Service Charge by considering the customer costs identified in the embedded cost of service study and the Demand Charge based on the demand costs identified in the embedded class cost of service study for those rate schedules where demand metering is warranted. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge, seasonal or service level differential and F&PP components for each rate schedule. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the pro forma sales under the applicable rate schedule. The calculations just described are provided for each rate schedule on pages 6-21 of Statement M and a summary of the proposed charges is provided on Statement M page 5. As explained further by Ms. Bosch, the Company is proposing to eliminate the Optional Residential Electric Thermal Energy Storage Rate 13.

Montana-Dakota continues to offer optional Time-of-Day (TOD) rate schedules consisting of Residential TOD Rate 16, Small General Service TOD Rate 26 and Large General Service TOD Rate 31. The rates have been designed to provide customers with an incentive to shift load to the off-peak period (all hours except for the hours from noon to 8:00 p.m. Monday through Friday).

A representation of the annual billing impact for each class is provided on Pages 22-35 of Statement M.

Q. Would you please explain how the Tax Tracker revenue is accounted for in the proposed final rate design?

A. Yes. Because the Tax Tracker revenue is collected via a tracker mechanism as a percentage of non-F&PP revenues, the entire allocation of the revenue increase and final rate design process must be completed before a new Tax Tracker rate can be established. In other words, we must know the non-F&PP revenues yielded by the proposed rate design before we can determine a Tax Tracker rate. To calculate the Tax Tracker rate to be in effect upon conclusion of this case the pro forma base tax revenue amount of $4,066,914, as sponsored in Mr. Jacobson’s testimony, is divided into proposed non-F&PP revenues total of $48,312,267 (page 4 of Statement M). The resulting 8.4180 percent Tax Tracker rate was used in each of the rate schedule calculations. The nature of this calculation, with the assumption that the tax amount is known and will not change, means the non-F&PP revenue increase amount and the Tax Tracker rate are inversely related. That is to say, if the non-F&PP revenue increase were to be adjusted downward, the Tax Tracker rate will correspondingly rise due to the denominator in its calculation decreasing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Allocation of Revenues - Interim
Pro Forma 2018

Customer Class	Kwh	KW	Base Rate	Energy	Demand	F&PP	Tax Tracker	Total	Revenue Increase $	Revenue Increase %
Residential Service	185,465,989		1,251,362	10,945,202		$4,714,545	$956,296	$17,867,405	$1,409,923	7.9%
Small General Service	121,217,232	340,492.2	1,083,911	4,485,299	1,703,328	3,081,342	570,217	10,924,097	840,705	7.7%
Large General Service	481,214,662	1,001,742.3	357,888	9,884,480	9,226,975	12,023,288	1,526,532	33,019,163	2,250,656	6.8%
Municipal Pumping	6,889,892	33,172.8	35,565	168,182	136,376	175,141	26,668	541,932	39,318	7.3%
Lighting	6,053,134			480,619		153,871	37,684	672,174	55,559	8.3%
Total Montana Electric	**800,840,909**	**1,375,407.3**	**$2,728,726**	**$25,963,782**	**$11,066,679**	**$20,148,187**	**$3,117,397**	**$63,024,771**	**$4,596,161**	**7.3%**

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Revenues at Proposed Rates
Pro Forma 2018

	Pro Forma Billing Determinants & Revenues											
Customer Class	**Customer**	**Kwh**	**KW**	**Base Rate**	**Energy**	**Demand**	**Tax Tracker Revenue**	**Fuel Rev**	**Total Revenue Before Increase**	**Total Proposed Revenue**	**Revenue Increase**	**% Incr**
Residential Service	20,167	185,465,989		$1,251,362	$10,945,202	$0	$956,296	$4,714,545	$17,867,405	21,796,355	$3,928,950	22.0%
Small General Service	5,903	121,217,232	340,492.2	1,083,911	4,485,299	1,703,328	570,217	3,081,342	10,924,097	12,973,327	2,049,230	18.8%
Large General Service	336	481,214,662	1,001,742.3	357,888	9,884,480	9,226,975	1,526,532	12,023,288	33,019,163	38,655,021	5,635,858	17.1%
Municipal Pumping	109	6,889,892	33,172.8	35,565	168,182	136,376	26,668	175,141	541,932	665,361	123,429	22.8%
Lighting	1,902	6,053,134			480,619		37,684	153,871	672,174	816,835	144,661	21.5%
Total Montana Electric	**28,417**	**800,840,909**	**1,375,407.3**	**$2,728,726**	**$25,963,782**	**$11,066,679**	**$3,117,397**	**$20,148,187**	**$63,024,771**	**$74,906,899**	**$11,882,128**	**18.9%**

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Residential Electric Service Rate 10
Interim Bill Comparison Worksheet

		Current Rates					Proposed Interim Rates						Bill Change	
	Kwh	Basic Service Charge	Energy	F&PP	Tax Tracker	Total	Basic Service Charge	Energy	F&PP	Tax Tracker	Interim	Total	$ Increase	% Increase
January	1,125	$5.17	$58.23	$28.60	$4.97	$96.97	$5.17	$58.23	$28.60	$4.97	$7.33	$104.30	$7.33	7.6%
February	900	5.17	46.58	22.88	4.06	78.69	5.17	46.58	22.88	4.06	5.98	84.67	5.98	7.6%
March	850	5.17	44.00	21.61	3.86	74.64	5.17	44.00	21.61	3.86	5.68	80.32	5.68	7.6%
April	600	5.17	31.06	15.25	2.84	54.32	5.17	31.06	15.25	2.84	4.19	58.51	4.19	7.7%
May	600	5.17	31.06	15.25	2.84	54.32	5.17	31.06	15.25	2.84	4.19	58.51	4.19	7.7%
June	650	5.17	47.59	16.52	4.14	73.42	5.17	47.59	16.52	4.14	6.10	79.52	6.10	8.3%
July	750	5.17	54.91	19.07	4.71	83.86	5.17	54.91	19.07	4.71	6.95	90.81	6.95	8.3%
August	1,000	5.17	73.21	25.42	6.15	109.95	5.17	73.21	25.42	6.15	9.06	119.01	9.06	8.2%
September	725	5.17	53.08	18.43	4.57	81.25	5.17	53.08	18.43	4.57	6.73	87.98	6.73	8.3%
October	600	5.17	31.06	15.25	2.84	54.32	5.17	31.06	15.25	2.84	4.19	58.51	4.19	7.7%
November	620	5.17	32.09	15.76	2.92	55.94	5.17	32.09	15.76	2.92	4.31	60.25	4.31	7.7%
December	780	5.17	40.37	19.83	3.57	68.94	5.17	40.37	19.83	3.57	5.26	74.20	5.26	7.6%
Total	9,200	$62.04	$543.24	$233.87	$47.47	$886.62	$62.04	$543.24	$233.87	$47.47	$69.97	$956.59	$69.97	7.9%
Average	767	$5.17	$45.27	$19.49	$3.96	$73.89	$5.17	$45.27	$19.49	$3.96	$5.83	$79.72	$5.83	7.9%

Rate 10 Current

Basic Service Charge	$0.17	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.07321	per Kwh
Winter Kwh (Oct-May)	$0.05176	per Kwh
Fuel & Purchased Power	$0.02542	per Kwh
Tax Tracking Adjustment	7.8407%	

Rate 10 Proposed Interim

Basic Service Charge	$0.17	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.07321	per Kwh
Winter Kwh (Oct-May)	$0.05176	per Kwh
Fuel & Purchased Power	$0.02542	per Kwh
Tax Tracking Adjustment	7.8407%	

Interim increase 11.560% of total of bill excluding F&PP and tax tracking adjustment components of bill.

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA

Residential Electric Service Rate 10
Bill Comparison Worksheet

		Current Rates					Proposed Rates					Bill Change	
	Kwh	Basic Service Charge	Energy	F&PP	Tax Tracker	Total	Basic Service Charge	Energy	F&PP	Tax Tracker	Total	$ Increase	% Increase
January	1,125	$5.17	$58.23	$28.60	$4.97	$96.97	$7.60	$73.53	$32.15	$6.83	$120.11	$23.14	23.9%
February	900	5.17	46.58	22.88	4.06	78.69	7.60	58.82	25.72	5.59	97.73	19.04	24.2%
March	850	5.17	44.00	21.61	3.86	74.64	7.60	55.56	24.29	5.32	92.77	18.13	24.3%
April	600	5.17	31.06	15.25	2.84	54.32	7.60	39.22	17.15	3.94	67.91	13.59	25.0%
May	600	5.17	31.06	15.25	2.84	54.32	7.60	39.22	17.15	3.94	67.91	13.59	25.0%
June	650	5.17	47.59	16.52	4.14	73.42	7.60	55.46	18.58	5.31	86.95	13.53	18.4%
July	750	5.17	54.91	19.07	4.71	83.86	7.60	64.00	21.44	6.03	99.07	15.21	18.1%
August	1,000	5.17	73.21	25.42	6.15	109.95	7.60	85.33	28.58	7.82	129.33	19.38	17.6%
September	725	5.17	53.08	18.43	4.57	81.25	7.60	61.86	20.72	5.85	96.03	14.78	18.2%
October	600	5.17	31.06	15.25	2.84	54.32	7.60	39.22	17.15	3.94	67.91	13.59	25.0%
November	620	5.17	32.09	15.76	2.92	55.94	7.60	40.52	17.72	4.05	69.89	13.95	24.9%
December	780	5.17	40.37	19.83	3.57	68.94	7.60	50.98	22.29	4.93	85.80	16.86	24.5%
Total	9,200	$62.04	$543.24	$233.87	$47.47	$886.62	$91.20	$663.72	$262.94	$63.55	$1,081.41	$194.79	22.0%
Average	767	$5.17	$45.27	$19.49		$73.89	$7.60	$55.31	$21.91		$90.12	$16.23	22.0%

Rate 10 Current

Basic Service Charge	$0.17	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.07321	per Kwh
Winter Kwh (Oct-May)	$0.05176	per Kwh
F&PP	$0.02542	per Kwh
Tax Tracker Adjustment	7.8407%	

Rate 10 Proposed

Basic Service Charge	$0.25	per month
Energy Charge		
Summer Kwh (June-Sept)	$0.08533	per Kwh
Winter Kwh (Oct-May)	$0.06536	per Kwh
F&PP & Transmission Expense	$0.02858	per Kwh
Tax Tracker Adjustment	8.4180%	

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

D2018.9.__

PREPARED DIRECT TESTIMONY OF

RALPH ZARUMBA

I. INTRODUCTION

A. Witness Identification

Q. **What is your name and business address?**

A. My name is Ralph Zarumba and my business address is 350 West Hubbard, Suite 600, Chicago, Illinois 60654.

Q. **By whom and in what position are you employed?**

A. I am a Vice President at Concentric Energy Advisors.

Q. **Please describe Concentric.**

A. Concentric Energy Advisors ("Concentric") provides regulatory, economic, market analysis and financial advisory services to energy and utility clients across North America. Our regulatory and economic services include regulatory policy, utility ratemaking (*e.g.*, cost of service, cost of capital, rate design, and alternative forms of ratemaking), compliance and regulatory audits, reviews of affiliate transactions, and assessments of the implications of regulatory and ratemaking policies on corporate governance. Our market analysis services include energy market assessments, market entry and exit analyses, and energy contract negotiations. Our financial advisory activities include merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services.

Q. **Please state your professional background.**

Q. My resume is attached as Exhibit RZ-1. In summary, I have 33 years of experience in various cost-of-service, pricing and regulatory issues associated with regulated utilities.

Q. **Have you previously testified before the Montana Public Service Commission (“Commission”)?**

A. No, I have not. However, I have testified before regulatory authorities in the following jurisdictions: the U.S. Federal Energy Regulatory Commission, Illinois, Wisconsin, Kansas, Texas, New Mexico, Massachusetts, Rhode Island, Puerto Rico, New York, New Brunswick, Nova Scotia, and Ontario. My testimonies addressed matters related to regulated utilities, pricing, cost of service and revenue requirements, regulatory policy, reconciling clauses, affiliate relations and cost allocation, and other related issues.

Q. **Who are you testifying on behalf of in this proceeding?**

A. I am testifying on behalf of Montana-Dakota Utilities.

Q. **Please summarize your experience preparing marginal cost studies.**

A. I have prepared marginal cost studies for regulated utilities for over thirty (30) years. Recent work has included an electric marginal cost study for the Puerto Rico Electric Power Authority, development of the water marginal cost study methodology and model in California and testimony supporting the use of marginal cost principles for electricity pricing in New Brunswick.

II. <u>PURPOSE AND SCOPE</u>

Q. **What are the purposes and scope of your testimony?**

A. I am sponsoring the Company’s Marginal Cost of Service Study.

Q. **Please describe what is a marginal cost of service study.**

A. A marginal cost of service study provides estimates of the next unit of cost incurred if the output of the utility increases. In the case of the study I have prepared for Montana Dakota Utilities the marginal cost study contains the following components:

1. Marginal Generation Capacity Cost;
2. Marginal Energy Cost;
3. Marginal Transmission Line Capacity Cost;
4. Marginal Transmission Substation Capacity Cost;
5. Marginal Distribution Capacity Line Cost;
6. Marginal Distribution Substation Capacity Cost;
7. Marginal Distribution Transformer Capacity Cost;
8. Marginal Distribution Customer Cost; and
9. Marginal Reactive Power Cost.

Q. **What is the time horizon of the Marginal Cost Study?**

A. The test year for the marginal cost study is 2019.

Q. **Does your study comport with Rule 38.5.176 – Statement L?**

A. Yes, I believe the study I am sponsoring comports with Rule 38.5.176 – Statement L.

III. DESCRIPTION OF EXHIBITS

Q. **Please describe the exhibits you are sponsoring in this proceeding.**

A. I am sponsoring Exhibits RZ-1 through RZ-3. The exhibits are as follows:

Exhibit RZ-1 Resume of Ralph Zarumba

Exhibit RZ-2 Report Estimating the Electric Marginal Cost of Montana Dakota Utilities Montana Jurisdiction

Exhibit RZ-3 Detailed Exhibits per the Marginal Cost of Service Model

Q. **Please outline Exhibit RZ-2, your report detailing the methodology used for the Marginal Cost Study.**

A. The report begins with an executive summary which describes the methodology and the results of the study. Following the executive summary are chapters which address each elements of the study which includes the following:

- Marginal Generation Capacity Cost ("MGCC");
- Marginal Energy Cost ("MEC");
- Marginal Transmission Capacity Cost ("MTCC");
- Marginal Transmission Substation Cost ("MTSC");
- Marginal Distribution Lines Cost ("MDLC");
- Marginal Distribution Substation Cost ("MDSC");
- Marginal Distribution Transformer Cost ("MDTC");
- Marginal Reactive Power Cost ("MRPC"); and
- Marginal Customer Cost ("MCC").

IV. RESULTS OF THE MARGINAL COST STUDY

Q. **Please summarize the results of the Marginal Cost Study.**

A. The revenue responsibility produced by the Marginal Cost Study are detailed in Exhibit No.__(RZ-3) Page 1.1. The information from Exhibit No.__(RZ-3) Page 1.1 is summarized below.

Description		Total
Rate / Summary Customer Class		
Residential Rate 10	$	34,310,275
Small General Primary Rate 20	$	-
Small General Secondary Rate 20	$	14,731,257
General Space Heat Rate 32	$	135,084
Irrigation Power Rate 25	$	1,250,756
Large General Primary Rate 30	$	5,303,372
Large General Secondary Rate 30	$	11,147,473
Large General Service TOD Rate 31- Secondary	$	902,488
Large General Service TOD Rate 31- Primary	$	119,897
Contract Services Rate 35	$	12,336,904
Municipal Pumping Rate 48	$	698,150
Outdoor Lighting Rate 52	$	244,961
Street Lighting Company Owned Rate 41	$	196,676
Street Lighting Municipal Owned Rate 41	$	94,045
Total	$	81,471,338

V. CHANGES IN THE MARGINAL COST CALCULATION METHODOLOGY

Q. **Are you proposing any changes in methodology in this study compared to the Company's previous study?**

A. Yes. I have proposed a number of changes primarily impacting the Generation Capacity, Generation Energy and Transmission Line Capacity costs.

A. Changes in the Marginal Generation Capacity Cost Calculation

Q. **What changes are you proposing in the approach to calculate Marginal Generation Capacity Costs (MGCC)?**

A. In the past the Company has adopted an approach which calculating the payment stream associated with a Simple-Cycle Combustion Turbine ("SCCT") for eight (8) years. The average of the eight (8) year payments is the MGCC. In contrast I propose to use the levelized cost of SCCT.

Q. **Are any other changes proposed for the calculation of MGCC?**

A. I propose to change the application of the Adjustment for MISO Reliability Requirement.

Q. **How are you changing the application of the Adjustment for MISO Reliability Requirement?**

A. In the past the adjustment was only applied to the capital cost of the SCCT and ignored the Operations and Maintenance Expense as well as the other adders (e.g. General and Administrative Expense). If the level of load changes by 1 kilowatt the cost incurred is not only the capital cost of the SCCT but the O&M Expense and the other adders. Therefore, I am applying the Adjustment for MISO Reliability Requirement to the total MDCC calculation which results in a slight reduction compared to the previous calculation methodology.

B. <u>Changes in the Marginal Energy Cost Calculation</u>

Q. **What changes are you proposing for Marginal Energy Costs ("MEC")?**

A. The previous study averaged the forecasted MEC for 9 years. I propose to only use the value for the test year 2019.

C. <u>Marginal Transmission Line Cost Calculation</u>

Q. **Are you proposing a change in the approach for calculating Marginal Transmission Line Costs ("MTLC")?**

A. Yes. The approach I have adopted has identified only that portion of transmission line investment associated with serving load growth in the calculation of MTLC. The numerator of the equation is the transmission line investment associated with load growth and the denominator is the change in the Company's load.

Q. **What time period was examined in performing the analysis on MTLC?**

A. Concentric consulted with the Montana-Dakota Utilities for the years 2005 through 2019. The data for 2005 through 2017 is actual data and 2018-9 is forecasted data.

Q. **Did you place transmission investments into different categories?**

A. Yes. Transmission investments for that time period were placed into the following categories:

Projects Associated with Generation Interconnection: Transmission investment is normally required when a new utility scale generation unit is interconnected to the network. The investment which are typically required may transmission line extensions, substations, breakers and other associated equipment.

Transmission investments associated with generation interconnection are not associated with marginal costs because: (1) they are not triggered by load growth; (2) they are typically captured in the investment criteria when constructing a new generation facility.

Projects Associated with Replacement of Worn or Obsolete Infrastructure: Utilities replace worn-out or obsolete infrastructure in the normal course of business. In the case of transmission infrastructure which replaces existing investment but does not serve new load or increase the capability of the system, equipment in this category is excluded for the calculation of marginal investment.

Projects which Enhance Transmission Reliability: Many transmission projects enhance the reliability of the system and provide value to customers. However, the capability to service new load is unrelated to this investment. Examples of transmission reliability investments could include the construction of a redundant transmission line between two points on the network.

Unless a reliability investment serves new load or provides the capability to serve new load it is excluded from the calculation of marginal investment in the transmission system.

Transmission Projects Interconnecting to other Wholesale Markets: In the last two decades several major transmission projects have been constructed which increase the capability of enabling transactions from one region to another. Examples of these projects include significant transmission projects which have enabled the export of renewable energy resources such as wind generation to other regions. Other examples of transmission interconnection projects which enable wholesale market access provide arbitrage opportunities between high and low cost regions.

Transmission projects which interconnect wholesale markets do not service new load growth but are justified based upon energy cost savings which they provide. They are therefore excluded from any estimate of marginal transmission investment.

Transmission Projects associated with Load Growth: The final category of transmission investments is those associated with load growth. By definition, these investment are included in the category of marginal transmission investments.

Q. **What percentage of transmission line investments are associated with load growth?**

A. Approximately 20 percent of transmission line investments are associated with load growth.

D. <u>Changes in the Approach to Calculate Levelized Fixed Charge Rates</u>

Q. **What changes do you propose in the calculation of Levelized Fixed Charge Rates (“LFCR”)?**

A. Previously the Company adopted an approach which provided a Real Fixed Charge Rate (“RFCR”) which produces an identical value over the life of the asset. I propose to use a Nominal Fixed Charge Rate (“NFCR”) which increases over time.

Q. **What impact will the adoption of the NFCR have on the calculation of the marginal costs?**

A. The use of the NFCR will reduce the capital recovery components of the marginal cost calculations compared to the use of a LFCR.

Q. **Does this conclude your testimony?**

A. Yes.

Ralph Zarumba
Vice President

Ralph Zarumba is a Vice President with 33 years of experience specializing in regulatory issues and economic analysis associated with energy utilities in North America, Europe, Central America and Asia. Mr. Zarumba has appeared as an expert witness in a number of regulatory and legal proceedings addressing pricing, marginal and embedded cost of service, electric generation, transmission and distribution issues, unregulated operations of utility holding companies and regulatory treatment of Smart Grid investments. He has assisted clients in other matters including Depreciation Studies, valuation and evaluation of the results of competitive bidding for electric generation services.

Mr. Zarumba's testimonies have been presented before the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission ("FERC"), the Massachusetts Department of Public Utilities, the Rhode Island Public Utilities Commission, the Illinois Commerce Commission, the Wisconsin Public Service Commission, the Ontario Energy Board, the New York Public Service Commission, the New Mexico Public Regulation Commission, the Kansas Corporation Commission, the New Brunswick Utility Energy and Utilities Board as well as a number of other venues.

Mr. Zarumba has provided a number of papers and presentations on various regulatory, pricing design, cost-of-service and market analysis issues.

REPRESENTATIVE EXPERIENCE

Pricing

- On behalf of Enbridge Gas New Brunswick appeared as an expert witness on the topic of marginal cost analysis and its application to pricing in the New Brunswick Power rate request.
- On behalf of the Puerto Rico Electric Power Authority managed that company's first regulated rate request and was the witness supporting pricing design, marginal cost of service and embedded cost of service.
- Performed a Pricing Strategy for the South Carolina Public Service Company (Santee Cooper).
- Developed the Wisconsin Electric Power Company's first Curtailable Electric Tariff available to commercial customers.
- Prepared proposals for Retail Conjunctive Billing Pricing filed in Illinois and Wisconsin which were filed before the Illinois Commerce Commission and the Wisconsin Public Service Commission.
- Negotiated complex service contracts with thermal energy customers which led to a major expansion of the Wisconsin Electric Steam System.

- Prepared proposals for ancillary services pricing based upon market-based mechanisms for San Diego Gas and Electric Company.

- Completed the development of wholesale and retail rate designs for a southeastern G&T, an analysis of stranded cost exposure for a northeastern utility, and prepared a strategic plan for a large municipal utility.

Cost of Service

- For Heritage Gas prepared a cost allocation for a natural gas storage field which was presented before the Nova Scotia Utility and Review Board.

- Provided testimony in the proceedings reviewing the 2014 Nova Scotia Power Cost-of-Service study (NSPI-P-892-/M05473).

- Prepared and sponsored before the FERC a cost-of-service filing supporting a Reliability Must-Run filing on the Cayuga Operating Company.

- Managed a project team which completed a Remaining Life Study for the Western Minnesota Municipal Power Agency.

- For a confidential client reviewed the cost-of-service application for a natural gas distributor in Central Canada.

- Prepared a white paper for the Ontario Energy Board on apportion of regulatory commission costs to various stakeholders.

- Prepared a functional cost separation study for a regulated electric utility in Ontario.

Regulatory Policy

- Assisted the Ontario Energy Board in formulating a regulatory process and pricing design for Revenue Decoupling.

- Prepared a white paper on rate mitigation mechanisms for the Ontario Energy Board.

- Prepared an analysis of the pricing of voluntary renewable energy products for a Midwestern public power association.

- Prepared a financial plan, electric rate design and phase-in plan for a new electric generation plan for Fayetteville (North Carolina) Public Works Commission.

- The Ontario Energy Board desired to identify factors that potentially impede the combination of regulated distributors in that province. Mr. Zarumba co-authored a study which identified those factors and discussed policies in other jurisdictions.

Management Audit and Affiliate Code of Conduct

- Led the regulatory and financial review for a management audit of Jersey Central Power & Light on behalf of the New Jersey Board of Public Utilities.
- On behalf of a coalition of marketers and energy service companies Mr. Zarumba presented testimony before the Illinois Commerce Commission addressing affiliate rules and code of conduct.
- On behalf of a coalition of marketers and energy service companies Mr. Zarumba presented testimony before the Wisconsin Public Service Commission addressing affiliate rules and code of conduct.

Revenue Requirements

- Prepared a number of working capital studies for various distributors and transmitters in the Province of Ontario.
- For a confidential client prepared a benchmarking analysis of the costs of regulatory proceedings associated with the introduction of new electric generation.
- Managed a project for Commonwealth Edison Company in their Electric Rate Request (Illinois Commerce Commission Docket No. 10-467) in which a Cash Working Capital study was provided.
- Assisted Indianapolis Power & Light in preparing a cost recovery plan for Energy Efficiency and Demand Side Management Expenditures.

Demand Response

- Assisted the Building Owners and Managers of Chicago (BOMA/Chicago) develop a program where they can bid demand response based ancillary services into the PJM market.
- Prepared a presentation for the Public Utilities Commission of Ohio on Commercial and Industrial Dynamic Pricing and Demand Response in an unregulated regulatory environment.

Electric Transmission

- Assisted the Long Island Power Authority to purchase distribution, transmission and regulatory assets and prepared its non-jurisdictional open-access transmission tariff.
- Prepared the pricing portion of a FERC open access tariff (Docket No. ER96-96-43.000) for San Diego Gas and Electric Company; testified on revenue requirements and pricing including opportunity costs.
- Prepared a Reliability Must-Run for the Cuyahoga Generating Station which was filed with the Federal Energy Regulatory Commission and the New York Public Service Commission.

Generation Market Analysis

- For a major public power generation owner prepared a strategy of internal coal versus natural gas generation dispatch protocols including the treatment of liquidated damages.
- Co-authored a report for Nalcor on the feasibility and economics of the proposed development of the Lower Churchill Hydroelectric project.
- Prepared a number of electric market price forecasts for many regions of the United States and Central America.
- Supported the electric pricing and infrastructure analysis for a Least-Cost Resource Plan for San Diego County.
- Prepared an analysis of the saturation of coal-fired electric generation technology in the Western Electric Coordinating Council.
- Developed a long-run electric expansion plan for the Railbelt System in Alaska.
- Managed a team that prepared a long-term capacity and energy forecast for a medium-sized municipal utility.
- For Manitowoc Public Utilities prepared a resource plan evaluating various generation expansion options.

Merger, Acquisition and Divesture

- On behalf of the Minnesota Public Service Commission. Mr. Zarumba co-authored an analysis of the merger savings associated with the proposed Primergy Merger (the proposed combination of Northern States Power and Wisconsin Energy). The analysis included a detailed review of cost savings that would emanate from the merger and regulatory commitments made by the companies to regulatory authorities in Minnesota.
- For the Manitowoc Public Utilities prepared an analysis that evaluated the divesture of its transmission assets to the American Transmission Company.

International

- Assisted the Israel Public Utility Authority is electric tariff reviews for the Israel Electric Company and the Jerusalem District Electric Company.
- During the time period 2007 through 2017 sssisted the Albanian Electric Regulator in several rate requests, taring of staff and negotiations involving the privatization of the electric distribution system.
- Mr. Zarumba assisted the electric regulator in the Republic of Macedonia with various regulatory issues including pricing design, revenue requirements and privatization issues. Included in the assistance was the development of market designs for the electricity sector.
- Completed a tariff implementation plan proposal for the privatization of the distribution companies of the Bulgarian Electric Utility.
- Led a team to implement regulatory procedures and methodology for the electric power industry in Bosnia and Herzegovina.
- Conducted a study of the electric power market in El Salvador including a quantification of the level of generation market power using the Lerner Index.

WHITEPAPERS

- White Paper Prepared for the Ontario Energy Board on Approaches to Rate Mitigation for Transmitters and Distributors
- White Paper Prepared for the Ontario Energy Board Cost addressing Distributor Efficiency
- White Paper Prepared for the Ontario Energy Board Cost addressing Cost Assessment Models for Regulators
- Economic Issues Related to Tariff Development (with Thomas Welch)

PUBLICATIONS

- Public Utilities Fortnightly "Pricing Social Benefits - Calculating and allocating costs for non-traditional utility services" Ralph Zarumba, Benjamin Grunfeld and Koby Bailey, August 2013
- American Gas "Modernization: The Quest for 21st Century Utilities" Ralph Zarumba and Peter Haapaniemi, November 2012
- Public Utilities Fortnightly "Pre-Funding to Mitigate Rate Shock" Sherman Elliot and Ralph Zarumba, September 2012

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2016 – present)
Vice President
Director, Navigant Consulting
Director, Science Applications International Corporation
President, Zarumba Consulting
Management Consultant, Sargent & Lundy Consulting Group
President, Analytical Support Network, Inc.
Manager, Pricing Practice, Synergic Resources Corporation
Senior Analyst – San Diego Gas & Electric Company
Senior Analyst – Wisconsin Electric Power Company
Analyst 4 – Eastern Utilities Associates
Analyst – Illinois Power Company

EDUCATION

MA, Economics, DePaul University

BS, Economics, Illinois State University

Montana-Dakota Utilities Co.

Electric Marginal Cost of Service Study

September 25, 2018

CONCENTRIC ENERGY ADVISORS

WWW.CEADVISORS.COM

Contents

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List of Acronyms

Acronym	Description
AFUDC	Allowance for Funds Used During Construction
FCR	Fixed Charge Rate
FOM	Fixed Operations and Maintenance
G&A	General and Administrative Expenses
KW	Kilowatt
KWH	Kilowatthour
MCC	Marginal Customer Cost
MCOSS	Electric Marginal Cost of Service Study
MDC	Marginal Distribution Costs
MDCC	Marginal Distribution Capacity Costs
MDCust	Marginal Distribution Customer Costs
MDLC	Marginal Distribution Lines Cost
MDLE	Marginal Distribution Line Expense
MDSC	Marginal Distribution Substation Cost
MDSE	Marginal Distribution Substation Expense
MDTC	Marginal Distribution Transformer Cost
MDU	Montana-Dakota Utilities
MEC	Marginal Energy Costs
MGCC	Marginal Generation Capacity Cost
MGEC	Marginal Generation Energy Costs
MISO	Midcontinent Independent System Operator
MPSC	Montana Public Service Commission
MRPC	Marginal Reactive Power Cost
MTCC	Marginal Transmission Capacity Costs
MTLCC	Marginal Transmission Line Capacity Costs
MTOME	Marginal Transmission Operations and Maintenance Expenses
MTSCC	Marginal Transmission Substation Capacity Cost
MW	Megawatt
MWH	Megawatthour
NCP	Non-Coincident Peak
NPV	Net Present Value
O&M	Operations and Maintenance
RICE	Reciprocating Internal Combustion Engine
ROE	Return on Equity
SCCT	Simple Cycle Combustion Turbine
WACC	Weighted Average Cost of Capital

SECTION 1:
EXECUTIVE SUMMARY

DESCRIPTION OF ENGAGEMENT

Concentric Energy Advisors ("Concentric") has been retained by Montana-Dakota Utilities ("Montana-Dakota") to perform an Electric Marginal Cost of Service Study ("MCOSS") for its Montana customer base. Montana-Dakota, a division of MDU Resources Group, Inc., provides natural gas service to roughly 272,000 customers and electric service to approximately 143,000 electric customers in North Dakota, South Dakota, Wyoming, and Montana.[1]

Montana-Dakota operates an integrated electric system with service territories in Montana, North Dakota, and South Dakota. Its primary existing resources consists of baseload coal-fired generation at the Heskett Station (Units 1 and 2), the Lewis and Clark station 1 and Montana-Dakota's share of the Coyote and Big Stone Stations. In addition, Montana-Dakota has natural gas peaking stations at Glendive, Miles City, Haskett 3 and Lewis and Clark 2. It also has wind generation at Diamond Willow, Cedar Hills, and Thunder Sprit in addition to diesel and waste heat generation units.

Montana-Dakota is a member of the Midcontinent Independent System Operator ("MISO"). Under MISO terms and conditions, Montana-Dakota cedes operating oversight to MISO and in return MISO provides Montana-Dakota access to a larger generation market. One benefit of this larger market is that Montana-Dakota can share resources and benefit from the diversity associated with a larger power pool. Under the MISO operation agreement MISO manages most of the Montana-Dakota transmission system at 115 kV and above. This report provides an estimate of Montana-Dakota's marginal cost for application to its Montana service territory. Since Montana-Dakota operates an integrated electric system, marginal costs of system wide services, namely generation and transmission, are necessarily based on the entire system whereas facilities that provide service to a local area, namely distribution facilities and customer hookup costs (meters, services, etc.) are estimated on a local basis.

The import of marginal cost estimates relates to the economic costs of providing service. Many economists argue that marginal costs represent the opportunity cost of providing another incremental of service and, as such, provide the proper price signal for both consumers and producers. Moreover, demand resources, energy efficiency and the pricing of services to customers can be improved by understanding the marginal cost of service. Since marginal cost is the change in cost as output changes by a small amount, this report has estimated those marginal costs that are related to changes in capacity (kWs), energy (kWh) and the

[1] MDU Resources also provides natural gas distribution services through its subsidiaries in portions of Minnesota, Idaho, Washington, and Oregon.

number of customers. In addition, since these costs can change by time of day and season, this report takes those changes into account as well.

MARGINAL COST OF SERVICE STUDY

An MCOSS measures the change in cost triggered by a change in the level of consumption faced by the utility. In the case of a vertically integrated utility such as MDU, the MCOSS will include marginal cost estimates for the generation, transmission and distribution functions.

In preparing this MCOSS, Concentric reviewed and adhered to Rule Section 38.5.176 which provides guidance for the development of marginal and allocated cost of service analyses filed before the MPSC. Rule Section 38.5.176 specifies the following requirements relevant to electric service:

(1) A generic marginal cost model shall also be provided. Marginal cost of service shall be determined for each of the following functions:

- (a) Generation, transmission, substation, distribution, and customer for electric filings.

(2) Marginal costs shall be determined using the following additional steps:

- (a) Classify the functionalized costs as energy (commodity), capacity, reactive power and/or customer related and compute the associated marginal unit costs.
- (b) Multiply classified marginal unit costs by allocation factors to compute total marginal cost.

COMPONENTS OF THE MARGINAL COST STUDY

The following components were estimated in this study.

- Marginal Generation Capacity Cost (“MGCC”);
- Marginal Energy Cost (“MEC”);
- Marginal Transmission Capacity Cost (“MTCC”);
- Marginal Transmission Substation Cost (“MTSC”);
- Marginal Distribution Lines Cost (“MDLC”);
- Marginal Distribution Substation Cost (“MDSC”);
- Marginal Distribution Transformer Cost (“MDTC”);
- Marginal Reactive Power Cost (“MRPC”); and
- Marginal Customer Cost (“MCC”).

METHODOLOGY FOR ESTIMATING MARGINAL COSTS

Concentric approach to estimating marginal costs followed the following process.

MARGINAL COST COMPONENTS WHICH INCLUDED CAPITAL EXPENDITURES

In cases where the component included capital Concentric calculated the incremental investment per relevant unit (e.g. kilowatt, customer or kilovolt-ampere) the following process was used for the estimate of marginal cost:

- The incremental investment for that component of marginal cost;
- A Fixed Charge Rate (FCR) was applied to the incremental investment producing an annualized value for that investment;
- A general plant adder was included producing the annualized cost of the general plant adder;
- Incremental Operations and Maintenance Expenses were captured which represent those expenses required to support the incremental investment;
- Capacity-related General and Administrative Expenses were added which represent the overhead functions required to support the incremental investment;
- The level of property taxes was estimated and included into the estimate;
- Working Capital was added; and
- Revenue taxes were added.

All estimates were escalated to the test year (2019).

MARGINAL COST COMPONENTS WHICH ARE COMPOSED ENTIRELY OF EXPENSES

In the case of marginal cost components which are composed entirely of expenses (e.g. Marginal Energy Costs) the expenses are the only component and estimates for 2019 were included in the study.

CHANGES IN METHODOLOGY

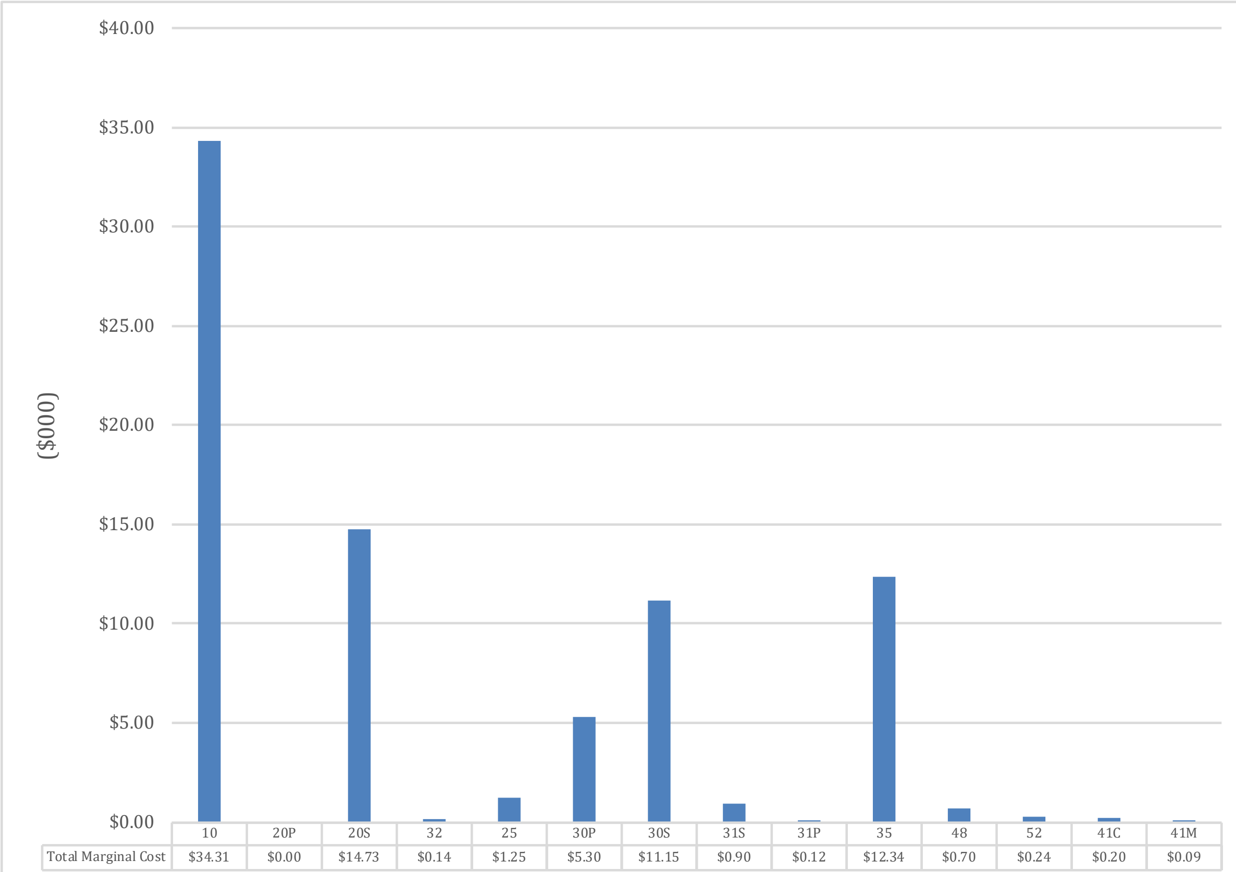
The methodologies used in this marginal cost study differed from previous studies in order to reflect the marginal cost of the company more accurately. The methodological changes included the following:

- The estimation of Marginal Generation Capacity Costs used the levelized installed cost of a combustion turbine. The approach employed in this study is sometimes referred to as the "Peaker Approach". The previous methodology used the cost over the first several years of the asset's life;
- Marginal Energy Costs were estimated for the test year only. Previous studies averaged MEC for several years;
- Marginal Transmission Lines Cost were estimated based upon those transmission investments that were related to load growth. Transmission investments which were related to replacement of existing infrastructure, interconnection of generators, reliability enhancements or interconnections to other wholesale markets were excluded from the analysis; and
- Fixed Charge Rates were calculated on a nominal basis whereas previous studies calculated the FCR on a real basis.

SUMMARY OF RESULTS

The results of this study are summarized in Figure 1 below:

Figure 1 – Results of the Marginal Cost Study by Tariff Class



The total marginal cost revenue requirement for the test-year is $81,471,338, which is approximately 25 percent lower than the previous study. The decrease in marginal cost is primarily attributable to the adoption of a single year for the estimate of Marginal Energy Costs versus multiple years. However, other capital-related marginal costs also decreased due to the change in the calculation of Fixed Charge Rates.

The distribution of cost responsibility calculated in the current study does not significantly differ from the previous study.

SECTION 2:
MARGINAL GENERATION CAPACITY COSTS

MDU operates a fleet of electric generating units which include coal-fired steam units, natural gas fired units, diesel generators and renewable resources. Concentrics's approach to estimating Marginal Generation Capacity Costs ("MGCC") focuses on the technologies or market-based solutions which provide capacity regardless of the cost of the energy incurred when that technology is dispatched. Concentrics's rationale for this approach is that a system planner will construct a more expensive base-loaded generating technology only when the reduction in energy costs offsets the increased fixed costs of that technology versus a lower fixed cost over the life of the unit. Therefore, the MGCC is defined as being *no more* than the levelized cost of the least capital-intensive technology which can reliably serve load. While MDU is part of the MISO, the MGCC estimated in this report is for the purposes of understanding the MGCC for providing service over the long-run to retail customers in Montana. Long-run marginal generation capacity costs must be related to the lowest cost technology that can provide capacity. We caution, however, that while utilizing this approach for pricing or cost allocation related to retail tariffs is appropriate, this approach would not necessarily be appropriate for the purposes of setting tariffs for purchasing capacity in any given time period, for example, from a distributed energy resource. In that case, where energy resources are in direct competition with the provision of retail services a more detailed analysis would need to be undertaken to determine the appropriate capacity price.

MGCC are the costs incurred when serving an additional kilowatt of load. In estimating MDU's MGCC, Concentric has used the incremental cost of the lowest-cost technology to provide capacity. Concentric used this approach for two reasons: First, we understand this estimation of marginal costs to be used for allocation of costs and perhaps for supporting retail tariff pricing for the monopoly utility. Second, this approach is broadly consistent with the approach used by Montana-Dakota in previous filings. To implement this approach Concentric determined that the lowest cost resource to provide generation capacity in the Montana-Dakota service territory is one of the commercially available combustion turbines.

INCREMENTAL COST OF A COMBUSTION TURBINE

The process employed by Concentric estimating the avoided cost of a combustion turbine is described below. The process followed the following steps:

- Determine the technology choice;
- Determine the annual cost through the application of a Fixed Charge Rate;
- Identify and add Fixed Operations and Maintenance Expenses; and
- Include adders for Administrative and General Expenses and Cash Working Capital.

TECHNOLOGY CHOICE

The avoided cost of a combustion turbine estimates the MGCC as the levelized cost of the least capital-intensive generation technology which can reliably serve load regardless of the cost of energy required by that technology. It should be noted that the "least capital-intensive technology" may differ from the "least-cost technology" identified in a resource planning analysis. The resource planning analyses considers the capital cost of a unit, the cost and quantity of the energy produced by various technologies and other factors when determining an optimal resource plan.

In order to determine which generation technology is most appropriate given MDU's circumstances Concentric reviewed MDU's most recent electric resource plan for information on potential generation technologies available to MDU, as listed in Table 1 below:

Table 1 – Resource Alternative Available to Montana-Dakota Utilities

EGEAS Model Input Summary, 2017$	Plant Size (MW-net)	ZRC	Capital Cost ($/KW)	Fixed O&M ($/KW-	Fuel Gas Reservation Fee ($/KW-yr)	Full Load Heat	Carbon Intensity (tons/GWH)	Fuel Cost ($/MMBTU)
GE 7EA	78.4	74.00	$1,163.27	$21.46	$2.67	11,498	672.5	$2.96
GELMS 100PS	90.5	85.42	$1,326.88	$24.91	$1.92	8.832	526	$2.96
GE LM6000PH	41.3	40.85	$1,546.30	$36.39	$2.72	9.637	563.5	$2.96
GE LM6000PH	66.1	63.51	$1,812.47	$65.41	$1.83	7.834	458	$2.96
GE 7EA (2*1)	265.1	254.71	$1,001.68	$30.23	$1.45	7.694	450	$2.96
GE 7FA, .05 (1*!)	323.0	310.34	$1,071.21	$27.97	$1.24	6.859	401	$2.96
Siemens SGT-800	139.8	134.33	$1,512.33	$41.56	$1.50	7.415	433.5	$2.96
Wartsila	36.5	36.10	$1,351.68	$44.56	$1.36	8.447	494	$2.96
Wartsila	56.3	54.70	$1,382.61	$44.34	$1.02	8.288	485	$3.96
Biomass	9.3	8.51	$9,211.23	$123.52		14.273	1859	$6.75
PV Solar	50.0	25.00	$2,854.74	$18.60				$0.00
Conc. Solar	50.0	25.00	$11,476.47	$76.80				$0.00
CFBC w/o	168.0	157.26	$5,623.15	$235.44		9.974	973	$1.91
CFBC w Carbon	122.0	114.20	$10,308.28	$323.16		13,781	124	$1.91
ND Wind	20.0	4.16	$1,542.03	$74.64				$0.00
ND Wind	50.0	10.40	$1,519.03	$74.64				$0.00

Source: MDU 2017 Integrated Resource Plan Submitted to the Montana Public Service Commission, Vol. IV Attachments C

In the case of MDU the technology which was adopted for this analysis was the General Electric 7EA ("GE 7EA") Simple Cycle Combustion Turbine ("SCCT"). The GE 7EA was chosen for the following reasons:

- The GE 7EA has a low installed capital cost compared to the majority of the other technologies. The one technology with a lower installed capital cost was the GE 7FA-05. However, the plant size of the GE 7FA-05 is very large compared to MDU's system size and was therefore rejected;

- MDU has operational experience with the GE 7EA and has recently installed that technology;
- The aero-derivative technologies (i.e. GE LMS100 and LM6000) were not adopted because they have capital costs in excess of the GE 7EA;
- The Reciprocating Internal Combustion Engine (“RICE”) technology options are a size which is appropriate for MDU but have capital cost in excess of the GE 7EA.

The installed cost of the GE 7EA technology is $1,163.27/kilowatt in 2017. The installed cost was escalated to the test year 2019 assuming a 2 percent annual inflation rate.

Table 2 – Escalation Rates for GE 7EA Simple-Cycle Combustion Turbine

Year	Inflation Rate	GE 7EA Installed Cost - $/Kilowatt
2017		$ 1,163.27
2019	1.04000	$ 1,209.80

DETERMINATION OF ANNUAL CAPITAL COST

Once the installed costs are calculated for the relevant years, a fixed charge rate was used to convert one-time capital costs to annualized costs. Consistent with past practice, Concentric used a levelized FCR to convert the installed cost of the GE 7EA technology to an annual cost.

Appendix A provides a discussion of the methodology employed to calculate the FCR used in this study and detailed calculations of all FCRs. The FCR rate used to produce the annualized capital cost of the GE 7EA technology was 8.96 percent producing an annual capital cost of the GE 7EA technology of $104.25 per kilowatt-year.

Table 3 – Determination of Annual Capital Cost of a GE 7EA Simple-Cycle Combustion Turbine

Year	Amount
GE 7EA Installed Cost - $/Kilowatt	$1,163.27
Fixed Charge Rate	8.96%
Annual Capital Recovery Cost for GE 7EA Installed Cost - $/Kilowatt	$104.25

FIXED OPERATIONS AND MAINTENANCE EXPENSE

Fixed Operations and Maintenance Expenses (“FOM”) for a simple-cycle combustion turbine are those costs which an operator incurs to maintain the unit for dispatch even if not output is produced. Examples of FOM include labor to staff the station, certain taxes and other similar expenses.

The total FOM for the GE 7EA technology in 2017 dollars was $18.79[2]. Concentric escalated the FOM to the appropriate values as detailed in the table below:

Table 4 – Escalation of the of Annual Fixed Operations and Maintenance Expense of a GE 7EA Simple-Cycle Combustion Turbine

Year	Amount
Fixed Operations and Maintenance Expense - 2017	$18.79
Escalation – 2017 to 2019	1.040
Fixed Operations and Maintenance Expense - 2019	$19.54

Item	Test-Year
Installed Cost of a Combustion Turbine (2017$/kW)	$ 1,163.27
Fixed Charge Rate (%)[3]	8.96%
Annual Capital Cost of a Combustion Turbine ($/kW – yr)	$ 1,209.80
Fixed Operations and Maintenance Expense	$ 19.54
General and Administrative Expenses[4]	$ 5.06
Property Taxes[5]	$ 0.30
Revenue Taxes[6]	$ 0.39
Working Capital Expenses[7]	$ -
Annual Installed Cost of a Combustion Turbine (2017$/kW)	$128.79
Escalation Rate	1.040
Annual Installed Cost of a Combustion Turbine (2019$/kW)	$ 135.51

[2] Concentric did not include the fuel reservation charge because it is associated with the procurement of natural gas and therefore not related to the calculation of MGCC.
[3] Appendix A.
[4] Appendix B.
[5] Appendix C.
[6] Appendix G.
[7] Appendix D.

SECTION 3:
MARGINAL GENERATION ENERGY COSTS

Marginal Generation Energy Costs ("MEC") are the costs incurred by MDU when the dispatch of their system is increased. MEC can be supplied either by the dispatch of MDU's own generating units or wholesale power market transactions.

The MEC estimates were supplied to Concentric by MDU, who used the PLEXOS market model. A summary of the MEC for 2019 are provided in the table below:

Table 5 – Marginal Energy Costs by Season and Time-of-Use

	2019		
	Non-Summer	**Summer**	**Annual**
Off-Peak	$23.54	$24.27	NA
On-Peak	$24.24	$27.22	NA
All Hours	NA	NA	$24.06

Concentric has changed the approach used to calculating MEC compared to the previous study by only using the MEC for the test-year. Our rationale for the change in the methodology is:

- The test year should reflect the costs in that time period. Using an average of several years of data reflects costs for future years;
- Recent history indicates that projections of MEC are dependent upon a number of variables such as the market price of natural gas, policies supporting the development of renewable energy resources and other market characteristics. The ability of forecast these variables into the future decreases with time and can introduce uncertainty into the MEC estimates; and
- Marginal cost studies can be provided in the future reflecting current information.

SECTION 4:
MARGINAL TRANSMISSION LINE CAPACITY COST

Electric transmission systems in the United States are network systems which provide redundancy to support reliability to the system. MDU's transmission system is interconnected to a number of other transmission systems in the region which further facilitate reliability and wholesale market transactions.

MDU Staff shared with Concentric that the company was currently completing a major transmission construction cycle. A similar construction cycle occurred in the late 1970s and early 1980s. As a result, the company has incurred a significant amount of transmission investment which will be associated with the future expected needs of the MDU system.

Marginal Transmission Capacity Cost ("MTCC") is the cost incurred to serve an additional kilowatt of load on the transmission system. Concentrics's analysis assumes that all transmission costs are functionalized as capacity related and no costs are energy related.

Concentrics's analysis of MDU's transmission system was separated into an analysis of transmission lines and an analysis of transmission substations.

CRITERIA FOR CONSTRUCTING NEW TRANSMISSION INFRASTRUCTURE

An MCOSS analysis is focused upon the change in costs which are incurred if the load of a utility increases. However, several reasons exist for utilities to construct transmission infrastructure which are unrelated to load growth. The criteria for constructing transmission infrastructure are listed below.

PROJECTS ASSOCIATED WITH GENERATION INTERCONNECTION

Transmission investment is normally required when a new utility scale generation unit is interconnected to the network. The investments which are typically required may include transmission line extensions, substations, breakers and other associated equipment.

Transmission investments associated with generation interconnection are not associated with marginal costs because:

(1) they are not triggered by load growth; and

(2) they are typically captured in the investment criteria when constructing a new generation facility.

PROJECTS ASSOCIATED WITH REPLACEMENT OF WORN OR OBSOLETE INFRASTRUCTURE

Utilities replace worn-out or obsolete infrastructure in the normal course of business. In the case of transmission infrastructure which replaces existing investment but does not serve new load or increase the capability of the system, equipment in this category is excluded for the calculation of marginal investment.

PROJECTS WHICH ENHANCE TRANSMISSION RELIABILITY

Many transmission projects enhance the reliability of the system and provide value to customers. However, the capability to service new load is unrelated to this investment. Examples of transmission reliability investments could include the construction of a redundant transmission line between two points on the network.

Unless a reliability investment serves new load or provides the capability to serve new load it is excluded from the calculation of marginal investment in the transmission system.

TRANSMISSION PROJECTS INTERCONNECTING TO OTHER WHOLESALE MARKETS

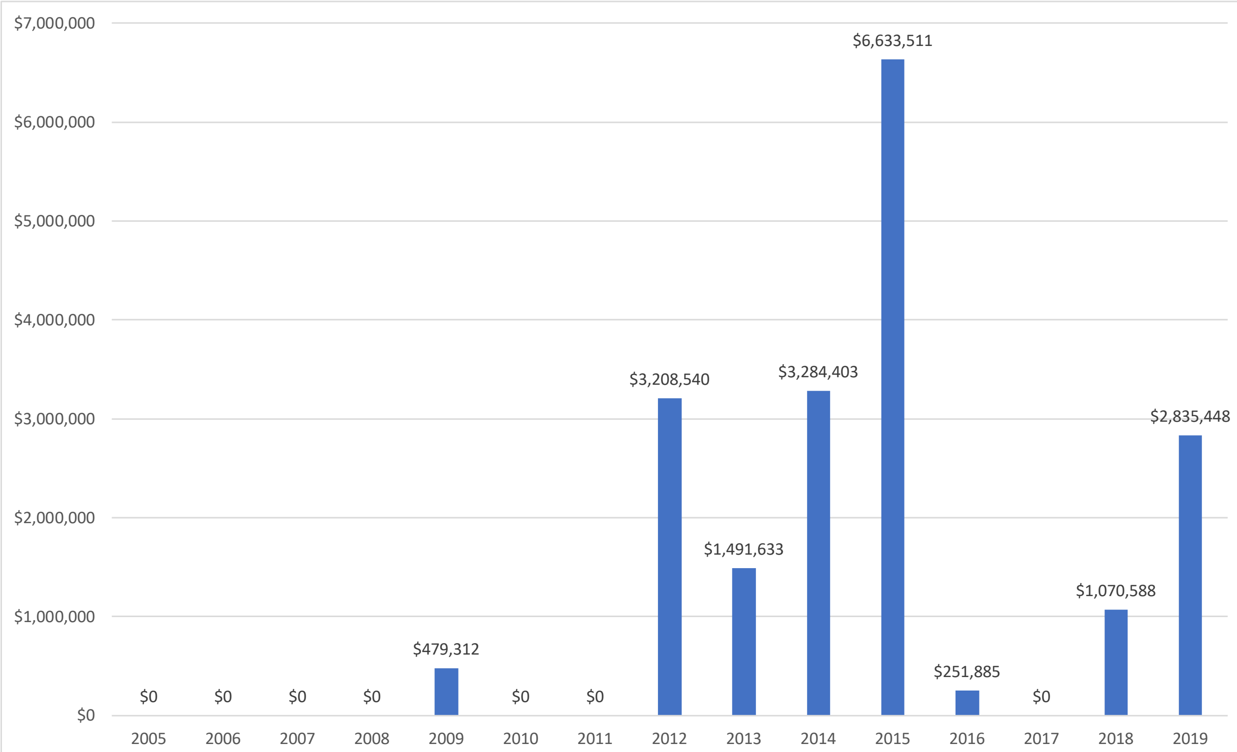
In the last two decades several major transmission projects have been constructed which increase the capability of enabling transactions from one region to another. Examples of these projects include significant transmission projects which have enabled the export of renewable energy resources such as wind generation to other regions. Other examples of transmission interconnection projects which enable wholesale market access provide arbitrage opportunities between high and low-cost regions.

Transmission projects which interconnect wholesale markets do not service new load growth but are justified based upon energy cost savings which they provide. They are therefore excluded from any estimate of marginal transmission investment.

TRANSMISSION PROJECTS ASSOCIATED WITH LOAD GROWTH

The final category of transmission investments is those associated with load growth. By definition, these investments are included in the category of marginal transmission investments. Figure 2 provides an illustration of the annual expenditures in load related transmission investments for the time period 2005 through 2019. Appendix E lists individual transmission projects and the category they have been assigned.

Figure 2 – Annual Transmission Investments Associated with Load Growth - 2005 through 2019

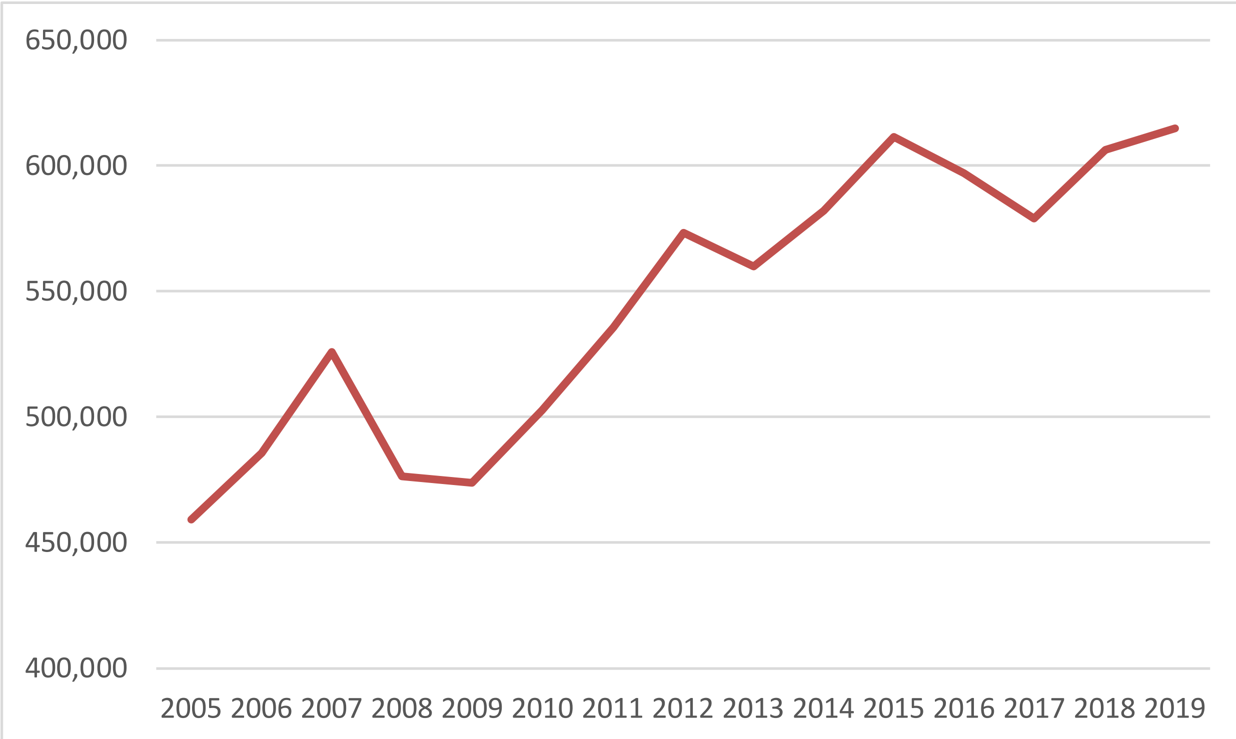


When restated into 2017 dollars MDU has made or is expected to make load related transmission investments of $19,255,321 related to load growth during the time period 2005 through 2019.

MONTANA-DAKOTA UTILIITES LOAD GROWTH

Concentric used historical and forecast data in order to determine the level of load growth on the MDU transmission system. Figure 3 illustrates the peak load data for the MDU transmission system for the historical years 2005 through 2017 and the forecast years 2017 through 2019. The extended time period for the analysis is required in order to capture the proper relationship between transmission investment and load growth.

Figure 3 – Historical and Forecasted MDU Load Growth (Kilowatts)



DETERMINATION OF AVERAGE INCREMENTAL INVESTMENT PER KILOWATT

Transmission investment occurs at irregular intervals and often is described as "lumpy" in nature. Therefore, in order to normalize investments which, occur infrequently, these investments must be analyzed over multiple years to normalize fluctuations.

The total investment for the analysis periods is divided by load growth providing average investment per kilowatt of load growth. Table 6 below provides these calculations for transmission lines and transmission substations which produce incremental investment per kilowatt.

Table 6 – Determination of Marginal Transmission Line Investment per Kilowatt

Item	Amount
Total Load Related Transmission Investment for the year 2005 through 2019 (2017 $)	$19,255,321
Change in Transmission System Peak Load (Megawatts)	155,770
Marginal Transmission Line Investment per Kilowatt (2017$)	$123.61
Escalation – 2017 to 2019	1.040
Marginal Transmission Line Investment per Kilowatt (2019$)	$ 128.56

MARGINAL TRANSMISSION OPERATIONS AND MAINTENANCE EXPENSES

Marginal Transmission Operations and Maintenance Expenses ("MTOME") were estimated based upon FERC Form 1 data for 2017. Transmission Operation and Maintenance Expenses were adjusted to eliminated expenses which are not considered marginal as well as for known and measurable changes. The expenses which were not included are as follows:

- Account 560 – reduction due to one-time expense associated with Southwest Power Pool;
- Account 561 – excluded because they are associated with dispatch and not related to supporting transmission infrastructure;
- Account 565 – Transmission by others is excluded because it is unrelated to supporting transmission infrastructure; and
- Account 562 and 570 – Station operations and maintenance expense were captured in marginal transmission substations costs.

Table 7 – Development of Marginal Transmission Line Capacity Cost

Incremental Investment in Transmission Lines (2017$/kW)	$ 123.61
Fixed Charge Rate (%)[8]	8.21%
Annual Capital Cost of Transmission Lines ($/kW – yr)	$10.15
Fixed Operations and Maintenance Expense	$ 12.07
General and Expenses[9]	$ 3.13
Property Taxes [10]	$ 0.11
Revenue Taxes[11]	$ 0.08
Working Capital Expenses[12]	$ 0.08
Annual Installed Cost of Transmission Lines – 2017$/KW	$25.18
Escalation Rate	1.040
Annual Installed Cost of Transmission Lines – 2019$/KW	$ 26.53

[8] Appendix A
[9] Appendix B
[10] Appendix C
[11] Appendix G
[12] Appendix D

SECTION 5:
MARGINAL TRANSMISSION SUBSTATION COSTS

Marginal Transmission Substation Cost ("MTSC") provides estimates of the cost of providing a kilowatt of transmission substation capacity. The approach adopted by Concentric is similar to past studies which estimated the cost of new transmission substation capacity on a on a per kilowatt basis.

ESTIMATION OF TRANSMISSION SUBSTATION INCREMENTAL INVESTMENT

Montana-Dakota provided Concentric with a listing of transmission substations which they recently constructed and the capacity of those substations. The substation information is provided in 8 below.

Table 8 – Transmission Substation Capital Costs

Facility	Year Installed	MW	Installed Cost	$/KW	Handy-Whitman or Inflation Index	2017 $	2017$/KW
Dickinson West Junction (2014 $)	2014	50	$5,591,682	$ 111.83	1.08	$6,038,457	$120.77
Ray Junction (2014 $)	2014	40	$5,781,931	$ 144.55	1.08	$6,243,907	$156.10
Lignite Junction (2014 $)	2014	40	$4,652,352	$ 116.31	1.08	$5,024,075	$125.60
Williston Little Muddy Junction (2014 $)	2014	50	$5,433,884	$ 108.68	1.08	$5,868,051	$117.36
Collins Trans Sub	2014	18	$1,438,251	$ 79.90	1.08	$1,553,167	$86.29
Mandan Refinery Trans Sub	2014	24	$2,179,555	$ 90.81	1.08	$2,353,701	$98.07
Baker Trans Sub (2016 $)	2016	50	$2,992,905	$ 59.86	1.03	$3,068,625	$61.37
Bowdle Trans Sub (2018 $)	2018	45	$5,476,800	$ 121.71	0.98	$5,369,412	$119.32
Leola Trans Sub (2018 $)	2018	45	$4,780,674	$ 106.24	0.98	$4,686,935	$104.15
Watford City Trans Sub (2018 $)	2018	25	$5,771,725	$ 230.87	0.98	$5,658,554	$226.34
Ellendale 2 Trans Sub (2018 $)	2018	300	$27,718,300	$ 92.39	0.98	$27,174,804	$90.58
Miles City Southwest Trans Sub (2019 $)	2019	45	$5,462,132	$ 121.38	0.96	$5,250,031	$116.67
Total							**$109.68**

The transmission substations were placed or planned to be placed into service during the time period 2014 through 2019. The Handy-Whitman Index was used to restate all costs into 2017 dollars for substations placed into service from 2005 through 2017. An inflation rate of 2 percent per year was used for substations placed into service in 2018-9. The weighted average investment per kilowatt of substation capacity is $109.68 in 2017 dollars.

DETERMINATION OF ANNUAL CAPITAL COST

Concentric used a FCR to convert the Marginal Transmission Substation investment into an annual cost. Appendix A contains the details the development of the FCR.

Table 9 – Determination of Annual Capital Cost of Transmisison Substations

Item	Amount
Transmission Substation - $/Kilowatt – 2017$	$ 109.68
Fixed Charge Rate	7.90%
Annual Capital Recovery Cost for Transmission Substations - $/Kilowatt – 2017$	$8.67
Escalation Rate	1.040
Annual Capital Recovery Cost for Transmission Substations - $/Kilowatt – 2019$	$ 9.01

MARGINAL TRANSMISSION SUBSTATION OPERATIONS AND MAINTENANCE EXPENSE

Accounts 562 and 570 capture transmission substation expenses and were the basis for the calculation of Marginal Transmission Substations Operations and Maintenance Expense. Data from Montana-Dakota's FERC Form 1 was used to determine the value for 2017. The resultant operations and maintenance costs was divided by the transmission peak demand for 2017.

Table 10 – Calculation of Marginal Transmission Substation Operations and Maintenance Expense

Item	Amount
Account 562 - 2017	$610,716
Account 570 - 2017	$1,010,386
Total Transmission Substation Operations and Maintenance Expense	**$2,631,488**
Coincident Peak Demand - 2017	579,090
Marginal Transmission Substation Operations and Maintenance Expense - 2017	**$4.54**

CALCULATION OF MARGINAL TRANSMISSION SUBSTATION COST

Table 11 below provides the calculation of MTSC.

Table 11 – Calculation of Marginal Transmission Substation Cost

Item	Amount
Incremental Investment in Transmission Substations (2017$/kW)	$ 109.68
Fixed Charge Rate (%)[13]	7.90%
Annual Capital Cost of Transmission Substations (2017$/kW – yr)	$8.67
Fixed Operations and Maintenance Expense (2017$/kW – yr)	$ 4.54
General and Administrative Expenses[14] (2017$/kW – yr)	$ 1.23
Property Taxes[15]	$ 0.11
Revenue Taxes[16]	$ 0.04
Working Capital Expenses[17] (2017$/kW – yr)	$ 0.07
Annual Installed Cost of Transmission Substations – 2017$/KW	$14.66
Escalation Rate	1.040
Annual Installed Cost of Transmission Substations – 2019$/KW	$ 15.45

[13] Appendix A
[14] Appendix B
[15] Appendix C
[16] Appendix G
[17] Appendix D

SECTION 6:
MARGINAL DISTRIBUTION COSTS

Marginal Distribution Costs ("MDC") are those costs associated with delivery of electric service from the transmission system to the customer. MDC are classified as either Marginal Distribution Capacity Costs ("MDCC") or Marginal Distribution Customer Costs ("MDCust").

Marginal Distribution Capacity Costs are defined as those costs which are triggered by a change in demand by a customer. The components of MDCC would be a portion of the elements of the distribution system including conductors, poles transformers and other related infrastructure which change as demand on the distribution system increases.

Marginal Distribution Customer Costs are defined as the costs triggered when a customer interconnects to the distribution system. The elements of MDCust include the meters service drop and the portion of conductors, poles transformers and other related infrastructure which does not change as demand increases but is related to the number of customers served by the distribution system.

MINIMUM SYSTEM APPROACH

Consistent with past practice, Concentric separated distribution costs into a capacity and customer component using a Minimum System Analysis. The results of the Minimum System Analysis are summarized in Table 12 below.

Table 12 – Results of Minimum System Analysis

Montana Plant Account	Minimum System	Normal System	Customer Component as a Percent of Investment
Pole (Acct. 364)	$16,877	$23,306	72.4%
Overhead Conductor (Acct. 365)	$13,173	$14,231	92.6%
Subtotal	$30,050	$37,537	80.1%
URD Conductor (Acct. 367)	$62,452	$72,223	86.5%
Total Overhead and Underground Minimum System Customer Percentage	$92,502	$109,760	84.3%

MARGINAL DISTRIBUTION CAPACITY COSTS

Marginal Distribution Capacity Costs ("MDCC") are those distribution costs which change as the level of load served by the distribution system changes. The approach adopted in this study analyzed the following components of the distribution system:

- Distribution lines;
- Distribution substations; and
- Distribution transformers

MARGINAL DISTRIBUTION LINE COSTS

Marginal Distribution Line Costs ("MDLC") are the costs of conductors, poles and associated infrastructure on the distribution system. The MDLC are separated into two components:

- Capacity related cost; and
- Customer related cost. The Minimum System approach discussed above were used to determine those cost which were capacity versus customer related.

Incremental Distribution Line Investment was calculated as the capacity-related Montana portion of distribution line investment divided by the Montana jurisdiction NCP producing Incremental Investment per kilowatt. Table 13 below provides the calculation of Incremental Distribution Line Investment.

Table 13 – Incremental Distribution Line Investment

Item	Amount
Capacity Related Distribution Lines – 2017$	$ 1,044.08
Non-Coincident Peak - 2017	198,053
Incremental Distribution Line Investment per Kilowatt of Non-Coincident Peak - 2017	$ 140.44
Escalation Rate – 2017 to 2018	1.040
Incremental Distribution Line Investment per Kilowatt of Non-Coincident Peak - 2019	$ 146.06

Marginal Distribution Line Expense ("MDLE") was calculated as the capacity-related portion of Distribution Operations and Maintenance Expenses. Operations and Maintenance Expenses related to substations, meters, transformers and streetlighting were excluded the MDLE calculation.

Table 14 – Calculation of Marginal Distribution Line Expense

Distribution Operations and Maintenance Expense	Total Distribution O&M Expense	Street Lighting O&M Expense	Meter O&M Expense	Substation O&M Expense	Distribution Transformer O&M Expense	Demand and Customer Related O&M Expense
Operations Expense	$2,078,832	$31,947	$339,294	$121,101	$0	$1,586,490
Maintenance Expense	$1,318,716	$43,625	$3,043	$52,341	$43,581	$1,176,126
Total Operations and Maintenance	$3,397,548	$75,572	$342,337	$173,442	$43,581	$2,762,616
Demand Related Distribution Operations and Maintenance Expense - %						15.72%
Demand Related Distribution Operations and Maintenance Expense – 2017$						$434,377
Montana Jurisdiction NCP 2017						198,053
Marginal Distribution Line Expense						$2.19

Table 15 below summarizes the calculation of MDLC.

Table 15 – Calculation of Marginal Distribution Line Cost

Incremental Investment in Distribution Line Investment (2017$/kW)	$ 140.44
Fixed Charge Rate (%)[18]	8.49%
Annual Capital Cost of Capacity Related Distribution Lines ($/kW – yr)	$11.92
Operations and Maintenance Expense	$ 2.28
General and Administrative Expenses[19]	$ 0.59
Property Taxes[20]	$ 0.45
Revenue Taxes[21]	$ 0.05
Working Capital Expenses[22]	$ 0.09
Annual Installed Cost of Capacity Related Distribution Lines – 2017$/KW	$ 15.29
Escalation Rate - 2017 to 2019	1.040
Annual Installed Cost of Capacity Related Distribution Lines – 2019$/KW	$ 16.08

MARGINAL DISTRIBUTION SUBSTATION COSTS

The estimation of Marginal Distribution Substation Costs ("MDSC") was performed in a manner similar to transmission substations. The analyses performed is discussed below.

[18] Appendix A
[19] Appendix B
[20] Appendix C
[21] Appendix G
[22] Appendix D

Information on recent distribution substations constructed by Montana-Dakota was provided to Concentric which is provided below.

Table 16 – Incremental Distribution Substation Investment

Substation	Year Installed	Megawatts	Substation Total Cost	Substation Cost – 2017 $/Kilowatt
Bismarck 26th St & Ave D Dist Sub (2014 $)	2014	15.00	$ 1,876,950	$135.13
Williston Water Plant Dist Sub (2014 $)	2014	5.00	$ 621,139	$134.15
Dickinson West Dist Sub (2014 $)	2014	10.00	$ 879,660	$94.99
Epping Dist Sub (2014 $)	2014	3.75	$ 595,195	$171.40
Mandan Collins Dist Sub (2015 $)	2015	18.00	$ 1,947,558	$112.58
Wishek Dist Sub (2016 $)	2016	5.00	$ 532,040	$109.10
Williston Halliburton Dist Sub (2016 $)	2016	7.50	$ 719,110	$98.31
Williston Oasis Dist Sub (2016 $)	2016	7.50	$ 776,967	$106.22
Bismarck South 9th St Dist Sub (2017 $)	2017	18.00	$ 2,210,115	$122.78
Heil Dist Sub (2018 $)	2018	2.00	$ 349,331	$174.67
Leola Dist Sub (2018 $)	2018	2.50	$ 253,852	$101.54
Dickinson North Dist Sub (2019 $)	2019	10.00	$ 1,585,344	$158.53
Keystone Dist Sub (2019 $)	2019	20.00	$ 3,054,359	$152.72
Bismarck 26th St & Ave D Dist Sub (2014 $)	2014	15.00	$ 1,876,950	$135.13
Incremental Substation Investment per Kilowatt - 2017				$127.56

Marginal Distribution Substation Expense ("MDSE") were estimated based upon the Montana jurisdictional values for Accounts 582 and 592 divided by the Montana jurisdictional NCP. Table 17 – Calculation of Marginal Distribution Substation Expense details this calculation.

Table 17 – Calculation of Marginal Distribution Substation Expense

Distribution Operations and Maintenance Expense	Substation O&M Expense
Operations Expense	$121,101
Maintenance Expense	$52,341
Total Operations and Maintenance Expense	$173,442
Montana Jurisdiction NCP 2017	198,053
Distribution Substation O&M $/kW - 2017$	$0.88

The calculation of Marginal Distribution Substation Cost is provided in Table 18 below.

Table 18 – Marginal Distribution Substation Costs

Distribution Substation Investment per Kilowatt – (2017$/KW)	$ 127.56
Fixed Charge Rate (%)[23]	8.06%
Annual Capital Cost of Capacity Distribution Substations ($/kW – yr)	$10.28
Operations and Maintenance Expense	$ 0.88
Administrative and General Expenses[24]	$ 0.24
Working Capital Expenses[25]	$ 0.08
Annual Installed Cost of Distribution Substations – 2017$/KW	$11.90
Escalation Rate - 2017 to 2019	1.040
Annual Installed Cost of Distribution Substations – 2019$/KW	$ 12.52

MARGINAL DISTRIBUTION TRANSFORMER COST

Marginal Distribution Transformer Costs were estimated based upon the weighted average number of single- and three-phase transformers installed in Montana. The Minimum System analysis previously discussed was used to identify which portion of the transformer were customer-related versus capacity-related.

Table 19 below details the calculation of the capacity portion of Marginal Distribution Transformer Cost.

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[23] Appendix A
[24] Appendix B
[25] Appendix D

Table 19 – Calculation of the Capacity Portion of Marginal Distribution Transformer Cost

Item	Amount
Capacity Related Transformer Investment per Kilowatt – (2017$/KW)	$14.47
Fixed Charge Rate (%)[26]	8.49%
Annual Capital Cost of Capacity Related Transformer Investment ($/kW – yr)	$1.33
Operations and Maintenance Expense	$0.23
General and Administrative Expenses[27]	$0.06
Property Taxes[28]	$0.05
Revenue Taxes[29]	$ -
Working Capital Expenses[30]	$0.12
Marginal Transformer Capacity Cost - 2017/KW-year	$1.67
Escalation Rate - 2017 to 2019	1.040
Marginal Transformer Capacity Cost - 2019/KW-year	$1.76

MARGINAL DISTRIBUTION CUSTOMER COSTS

Marginal Distribution Customer Costs ("MDCust") are defined as the cost to provide a customer access to service regardless of the level of usage. The components of MDCust are as follows:

- Customer related transformer costs;
- Customer related distribution lines costs;
- The cost of Services; and
- The cost of meters.

Table 20 provides a summary of marginal distribution customer costs.

[26] Appendix A
[27] Appendix B
[28] Appendix C
[29] Appendix G
[30] Appendix D

Table 20 – Components of Marginal Distribution Customer Cost

MCOSS Customer Rate Class	Capital Recovery	O&M Expenses and Adders	Total Customer Related Marginal Cost
Residential Rate 10	$629.84	$100.27	$1,024.34
Small General Primary Rate 20	$875.80	$100.27	$1,321.58
Small General Secondary Rate 20	$774.78	$100.27	$1,235.09
General Space Heat Rate 32	$605.45	$100.27	$1,107.41
Irrigation Power Rate 25	$932.92	$100.27	$1,482.13
Large General Primary Rate 30	$1,293.26	$100.27	$2,239.51
Large General Secondary Rate 30	$968.92	$100.27	$1,580.58
Mandatory TOD Industrial Primary Rate 31	$860.34	$100.27	$1,717.76
Mandatory TOD Industrial Secondary Rate 31	$878.59	$100.27	$1,497.88
Contract Services Rate 35	$1,335.75	$100.27	$2,311.38
Municipal Pumping Secondary Rate 48	$772.83	$100.27	$1,256.17
Private Lighting Rate 52	$687.73	$100.27	$1,122.35
Street Lighting Company Owned Rate 41	$661.60	$100.27	$1,067.27
Street Lighting Municipal Owned Rate 41	$661.60	$100.27	$1,067.27

CUSTOMER-RELATATED INCREMENTAL INVESTMENT

Table 21 provides the incremental distribution investment per customer in 2017 dollars.

Table 21 – Customer-Related Distribution Investment by Tariff Class

Customer Rate Class	Transformer	Distribution Lines	Services	Meter	Total Incremental Customer-Related Investment
Residential Rate 10	$ 229	$ 4,759	$ 680	$ 91	$ 5,760
Small General Primary Rate 20	$ -	$ 4,759	$ -	$ 3,250	$ 8,009
Small General Secondary Rate 20	$ 1,590	$ 4,759	$ 529	$ 207	$ 7,085
General Space Heat Rate 32	$ -	$ 4,759	$ -	$ 778	$ 5,537
Irrigation Power Rate 25	$ 2,513	$ 4,759	$ 886	$ 373	$ 8,531
Large General Primary Rate 30	$ -	$ 4,759	$ -	$ 7,068	$ 11,826
Large General Secondary Rate 30	$ 1,924	$ 4,759	$ 1,066	$ 1,111	$ 8,860
Mandatory TOD Industrial Primary Rate 31	$ 1,405	$ 4,759	$ 1,107	$ 597	$ 7,868
Mandatory TOD Industrial Secondary Rate 31	$ -	$ 4,759	$ -	$ 3,276	$ 8,034
Contract Services Rate 35	$ -	$ 4,759	$ -	$ 7,456	$ 12,215
Municipal Pumping Secondary Rate 48	$ 1,095	$ 4,759	$ 698	$ 515	$ 7,067
Private Lighting Rate 52	$ 874	$ 4,759	$ -	$ 656	$ 6,289
Street Lighting Company Owned Rate 41	$ 874	$ 4,759	$ 327	$ 90	$ 6,050
Street Lighting Municipal Owned Rate 41	$ 874	$ 4,759	$ 327	$ 90	$ 6,050

CUSTOMER-RELATED DISTRIBUTION OPERATIONS AND MAINTENACE EXPENSE

The estimation of customer-related Operations and Maintenance Expense is provided in Table 22 below. The estimates are consistent with capacity-related O&M Expense calculations previously discussed.

Table 22 – Customer Related Distribution Operations and Maintenance Expenses

Item	Amount
Total Distribution Expenses	$2,762,616
Customer Related O&M Percentage	84.30%
Customer Related Distribution Operations and Maintenance Expenses	$2,328,885
Meter-related Operations and Maintenance Expenses	$342,337
Total Customer-related Operations and Maintenance Expenses	$2,671,222.29
Montana Jurisdiction Average Customers, 2017	26,641
Distribution Line Customer-Related O&M $/kW - 2017$	$100.27

CALCULATION OF MARGINAL DISTRIBUTION CUSTOMER COST

Table 23 below provides the results of the calculation of MDCC for each tariff class.

Table 23 – Marginal Distribution Customer Cost

MCOSS Customer Rate Class	Amount
Residential Rate 10	$1,024.34
Small General Primary Rate 20	$1,321.58
Small General Secondary Rate 20	$1,235.09
General Space Heat Rate 32	$1,107.41
Irrigation Power Rate 25	$1,482.13
Large General Primary Rate 30	$2,239.51
Large General Secondary Rate 30	$1,580.58
Mandatory TOD Industrial Primary Rate 31	$1,717.76
Mandatory TOD Industrial Secondary Rate 31	$1,497.88
Contract Services Rate 35	$2,311.38
Municipal Pumping Secondary Rate 48	$1,256.17
Private Lighting Rate 52	$1,122.35
Street Lighting Company Owned Rate 41	$1,067.27
Street Lighting Municipal Owned Rate 41	$1,067.27

SECTION 6

MARGINAL REACTIVE POWER COSTS

Concentric calculated the cost to correct for power factor adjustments consistent with practices adopted in previous studies. The approach used calculates the avoided cost of capacitor banks recently installed by the company stated.

Table 24 details the calculation of the Marginal Cost of Reactive Power. The avoided investment in capacitor banks for estimated based upon recently installed capacitor banks.

Table 24 – Marginal Cost of Reactive Power

Item	Amount
Investment per KVAR for Recently Installed Capacitor Banks – (2017$/KW)	$ 76.63
Fixed Charge Rate (%)[31]	8.49%
Annual Capital Cost of Capacitor Banks ($/kVAR – yr)	$6.50
Operations and Maintenance Expense	0
General and Administrative Expenses[32]	0
Property Taxes[33]	$ 0.25
Revenue Taxes[34]	$ 0.02
Working Capital Expenses[35]	$ 0.05
Marginal Reactive Power Costs - 2017/KW-year	$6.82
Escalation Rate - 2017 to 2019	1.040
Marginal Reactive Power Costs - 2019/KW-year	$ 7.08

[31] Appendix A.
[32] Appendix B.
[33] Appendix C.
[34] Appendix G.
[35] Appendix D.

APPENDIX A:
FIXED CHARGE RATE CALCULATIONS

A FCR calculates the revenue requirement over the life of an asset and provides the amount required to service the revenue requirement assuming a fixed amount is paid each year of the life of the asset. The process followed to calculate the FCR is provided below:

(1) Calculate the revenue requirement associated with the capital recovery based upon the installed cost of the asset. The capital recovery will include:

   a. Return of Equity (“ROE”);

   b. Interest Expense;

   c. Depreciation Expense;

   d. Income Taxes; and

   e. Other Taxes (if applicable).

(2) Apply the Weighted Average Cost of Capital (“WACC”) of the utility determined the Net Present Value (“NPV”) of the revenue requirement;

The FCRs used in this study are shown below.

Item	Fixed Charge Rate Value
Generation	8.96
Transmission Lines	8.21%
Transmission Substations	7.90%
Distribution Lines	8.49%
Distribution Substations	8.06%
Services and Meters	9.18%
General Plant	9.73%

APPENDIX B:
CALCULATION OF GENERAL AND ADMINISTRATIVE EXPENSE LOADING

The General and Administrative Expense adder provides an estimate of the amount of G&A Expense incrementally incurred as a unit of output increases. The approach adopted in this study calculated the ratio of G&A Expense in the test year in 2017 to the level of O&M Expense excluding Fuel Expense, Purchased Power Expense and G&A Expense. The table below provide this calculation.

Item	**Value**
Total Admin. & General Expense	$5,515,015
Total Company O&M Expense	$26,793,821
General & Administrative Expense Adder	25.9%

APPENDIX C:
PROPERTY TAX ADDER

Property Tax adders represent the level of Property Taxes incurred by the utility if plant is added. The property tax adders used in this study were calculated based upon tax and average plant data for 2017 and is provided below.

Function	@ 12/31/17	@ 12/31/17	Tax Rate
Production 1/	$231,942,233	$ 632,871	0.2729%
Transmission	$52,560,027	$ 668,687	1.2722%
Distribution	$65,067,458	$ 2,365,492	3.6354%
General	$6,873,065	$ 117,094	1.7037%
Common	$7,647,803	$ 105,117	1.3745%
Intangible 2/	$6,016,913	$ 37,019	0.6152%
Total	**$ 370,107,500**	**$ 3,926,280**	**Ties 9/13/18**

1/ Includes steam production, other production and AFUDC interest and depreciation on Coyote.

2/ General and common intangible.

APPENDIX D:
WORKING CAPITAL ADJUSTMENT

The calculation of marginal costs included a adjustment for the level of working capital associated with Materials and Supplies, Prepayments and Fuel Stocks. In the case of Material and Supplies and Prepayments the numerator was each variable and the denominator is Electric Plant in Service. In the case of Fuel Stocks the denominator is total megawatt hour sales. The calculation of Working Capital Adjustment is provided in the table below.

Working Capital Adders	**Denominator**
Materials & Supplies	\$2,667,010
Prepayments	\$215,229
Fuel Stocks	\$1,186,578
Total Electric Plant YE 2017 (2017 \$)	\$376,949,747
Total 2017 MWH Sales	800,841
Materials & Supplies Factor	\$2,667,010 / \$376,949,747 = 0.0071
Prepayments	\$215,229 / \$376,949,747 = 0.0006
Fuel Stocks	\$1,186,578 / 800,841 = \$0.00148/KWH

APPENDIX E:
TRANSMISSION INVESTMENTS – 2005 TO 2019

Year	From	To	Length (miles)	Total w/HW - 2017$		Cost / Mile		Investment Category	% Related to Load	Total Related to Load Growth - 2019	
(a)	(b)	(c)	(d)	(O)		(k)		(L)	(N)	(P)	
2005	Heskett	Devaul	0.22	$	165,647	$	752,943	1	0%	$	-
2006	Midway Sub Tap Line		0.11	$	53,003	$	481,848	1	0%	$	-
2006	Turnpike Ave Sub Tap Line		0.55	$	202,577	$	368,323	4	0%	$	-
2007	Diamond Wilow Tap Line		0.19	$	30,233	$	159,120	2	0%	$	-
2007	Cabin Creek Jct Tap Line		0.61	$	81,767	$	134,044	4	0%	$	-
2007	Jct TL080-1	East Bismarck	3.69	$	1,295,936	$	351,202	1	0%	$	-
2007	South Bismarck	East Bismarck	0.15	$	296,097	$	1,973,983	1	0%	$	-
2007	South Bismarck	East Bismarck	0.40	$	-	$	-	1	0%	$	-
2007	South Bismarck	East Bismarck	1.08	$	-	$	-	1	0%	$	-
2007	South Bismarck	East Bismarck	1.63	$	-	$	-	1	0%	$	-
2008	Baker	Glendive	0.11	$	116,608	$	1,060,072	1	0%	$	-
2008	Bowdle	Mobridge	0.18	$	8,323	$	46,240	1	0%	$	-
2008	Tioga	Kenmare	2.55	$	315,115	$	123,574	1	0%	$	-
2008	Bismarck	Loop Line	0.11	$	27,223	$	247,485	1	0%	$	-
2008	Northwest Bismarck	East Bismarck	0.12	$	123,975	$	1,033,124	4	0%	$	-
2008	Beulah	Bismarck	0.15	$	332,950	$	2,219,669	1	0%	$	-
2008	Beulah	Bismarck	0.44	$	2,032,222	$	4,618,685	1	0%	$	-
2008	South Mandan	Bismarck - Sweet Ave	0.45	$	858,928	$	1,908,729	1	0%	$	-
2008	South Mandan	Bismarck - Sweet Ave	0.40	$	1,744,468	$	4,361,171	1	0%	$	-
2008	Bismarck - Sweet Ave	TL403 & 405	0.34	$	533,372	$	1,568,741	4	0%	$	-
2008	Bismarck - Sweet Ave	TL403 & 405	0.20	$	-	$	-	4	0%	$	-
2008	Bismarck - Sweet Ave	TL403 & 405	0.46	$	1,675,127	$	3,641,580	4	0%	$	-
2009	Northern Border Pipeline	Tap Line	3.47	$	402,924	$	116,116	5	100%	$	402,924
2009	Glen Ullin, ND	Heart Butte - Elgin, ND	0.06	$	44,015	$	733,591	1	0%	$	-

2009	Dakota Westmoreland	Tap Line	0.31	$	76,388	$	246,414	5	100%	$	76,388
2010	Diamond Willow Tap Line	South Tap Line	0.10	$	26,282	$	262,824	2	0%	$	-
2011	South Mandan	Sweet Ave, Bismarck	0.01	$	211,235	$	21,123,504	4	0%	$	-
2012	Wishek	Ellendale	0.22	$	169,861	$	772,094	1	0%	$	-
2012	Merricourt Windfarm	Ellendale	29.69	$	10,033,267	$	337,934	2	0%	$	-
2012	OneOK Bakken Pipeline	Tap Line	1.34	$	208,778	$	155,804	5	100%	$	208,778
2012	Alexander	Watford City	17.77	$	3,068,090	$	172,656	1,5	50%	$	1,534,045
2012	NE Bismarck	Tap Line	2.85	$	2,735,028	$	959,659	5	25%	$	683,757
2012	Jct HL 39 NW Bismarck	East Bismarck	0.17	$	291,244	$	1,713,202	1	0%	$	-
2012	Ray Jct Sub	Tap Line (dbl Ckt)	2.61	$	1,284,206	$	492,033	4,5	50%	$	642,103
2012	Enbridge Stanley	Tap Line	0.21	$	139,857	$	665,987	5	100%	$	139,857
2012	MWEC Belden	Stanley	1.97	$	1,258,712	$	638,940	4	0%	$	-
2013	Matheson	Tap Line	2.63	$	1,048,022	$	398,487	5	100%	$	1,048,022
2013	Harvest Hills	Tap Line	1.53	$	529,222	$	345,897	5	30%	$	158,767
2013	Dakota Prairie Refining	Tap Line	0.44	$	197,159	$	448,088	5	100%	$	197,159
2013	Air Liquide	Tap Line	0.19	$	87,686	$	461,505	5	100%	$	87,686
2013	Heskett III	Tie Line	0.09	$	58,511	$	650,118	2	0%	$	-
2013	Heskett	Mandan Junction	0.85	$	263,297	$	309,762	4	0%	$	-
2014	Williston Loop Line		0.24	$	568,023	$	2,260,367	1	0%	$	-
2014	Dickinson West	Dakota Prairie Refinery	4.96	$	1,832,429	$	353,802	5	100%	$	1,832,429
2014	Dickinson West	Dakota Prairie Refinery	0.70	$	-	$	-	5	100%	$	-
2014	Medora	Dickinson	0.05	$	331,119	$	6,364,980	4	0%	$	-
2014	Watford City	Alexander	0.08	$	320,979	$	3,829,938	1	0%	$	-
2014	Watford City	Alexander	0.44	$	314,981	$	685,895	1	0%	$	-
2014	Stanley	Ross	7.17	$	1,201,424	$	160,497	5	30%	$	360,427
2014	Ray	Epping	11.07	$	1,831,319	$	157,940	5	50%	$	915,659
2014	Dakota Westmoreland	Tap Line	0.86	$	175,888	$	195,228	5	100%	$	175,888
2014	Williston	Tioga	0.82	$	565,349	$	658,123	4	0%	$	-

2014	Williston	WAPA Sub	0.82	$	151,394	$	176,238	4	0%	$	-
2015	Dickinson West	Dickinson Basin Jct.	5.75	$	3,078,323	$	528,080	4,5	30%	$	923,497
2015	Jct. TL011-1	Dickinson Jct. 46kV	5.43	$	1,200,698	$	219,034	4,5	30%	$	360,210
2015	Jct. TL011-1	Dickinson Jct. 46kV	0.20	$	-	$	-	4,5	30%	$	-
2015	Beulah	Dickinson	0.14	$	-	$	-	1	0%	$	-
2015	Rice Generator		0.07	$	116,724	$	1,641,686	2	0%	$	-
2015	Plevna	Baker	10.46	$	2,476,415	$	233,435	5	20%	$	495,283
2015	Collins 115kV	Tap Line	1.01	$	472,240	$	461,000	4	0%	$	-
2015	Baker	Glendive	6.15	$	1,365,588	$	218,882	1	0%	$	-
2015	Tap to NACO Sub		0.05	$	251,747	$	4,979,140	5	100%	$	251,747
2015	Tioga LNG Tap		0.14	$	281,435	$	1,989,243	5	100%	$	281,435
2015	Little Muddy Sub	Williston	9.49	$	8,823,954	$	913,891	4,5	25%	$	2,205,989
2015	Kenmare	Lignite	31.27	$	8,461,403	$	265,807	4,5	25%	$	2,115,351
2015	Hebron	Dickinson	0.23	$	203,350	$	873,500	1	0%	$	-
2016	Enbridge Stanley Tap		2.65	$	-	$	-	5	100%	$	-
2016	Medora	Dickinson	0.56	$	546,177	$	975,498	1	0%	$	-
2016	Dickinson 46kV West Tap Line		0.35	$	290,027	$	827,297	5	25%	$	72,507
2016	Oasis Tap Line		0.05	$	57,021	$	1,124,560	5	25%	$	14,255
2016	Williston Waste Water Plant		0.06	$	150,810	$	2,514,567	5	50%	$	75,405
2016	Correction to 2014 WO		0.07	$	-	$	-		0%	$	-
2016	Emerald Ridge Sub		0.60	$	358,873	$	592,682	5	25%	$	89,718
2017	Sidney Loop Line		3.46	$	2,645,340	$	764,549	4	0%	$	-
2017	Beaver Hill Tap Line		0.52	$	153,463	$	295,121	4	0%	$	-
2017	Miles City Loop Line		0.02	$	103,303	$	5,165,150	4	0%	$	-
2017	Dickinson North	Green River	7.30	$	148,088	$	20,286	4	0%	$	-
2017	Hettinger	Bowman	3.95	$	18,812	$	4,763	4	0%	$	-
2017	Hettinger	Bowman	3.95	$	-	$	-	4	0%	$	-
2017	South 9th Street Tap		0.75	$	467,192	$	622,923	1	0%	$	-

2017	Sweet Ave	South 9th	0.69	$ -	$ -	1	0%	$ -
2017	Dickinson North 41.6kV		2.35	$ 42,008	$ 17,876	4	0%	$ -
2017	Dickinson North 41.6kV		4.52	$ -	$ -	4	0%	$ -
2017	Collins Sub	Tesoro 46kV	1.45	$ 789,661	$ 544,594	4	0%	$ -
2017	Heskett Station	Refinery	0.13	$ 118,834	$ 914,108	4	0%	$ -
2017	Jct TL039-Century-CPEC Line		2.28	$ 126,070	$ 55,294	4	0%	$ -
2017	Dickinson NW Sub	Dickinson North Sub	1.72	$ 36,887	$ 21,446	4	0%	$ -
2017	West Dickinson Tap Line		0.01	$ -	$ -	4	0%	$ -
2018	Beach	Tap Line	1.00	$ 220,588	$ 225,000	5	100%	$ 220,588
2018	Leola	Tap Line	0.25	$ 78,431	$ 320,000	4	0%	$ -
2018	Williston	Water Plant	2.20	$ 1,133,333	$ 525,455	5	75%	$ 850,000
2018	Williston	Zavanna Reroute	0.35	$ 628,228	$ 1,830,837	4	0%	$ -
2018	Crosby	Tap Line	0.10	$ 51,222	$ 522,460	1	0%	$ -
2018	Heil	Tap Line	0.05	$ 62,745	$ 1,280,000	1	0%	$ -
2018	Tatanka	Ellendale	0.20	$ 181,834	$ 927,355	4	0%	$ -
2018	Merricourt	Ellendale	0.50	$ 615,704	$ 1,256,036	4	0%	$ -
2018	Sidney Loop Line		0.20	$ 380,363	$ 1,939,850	4	0%	$ -
2018	Sidney	Holly St Rebuild	1.10	$ 411,482	$ 381,556	1	0%	$ -
2018	Glendive	Cabin Creek	0.95	$ 137,255	$ 147,368	1	0%	$ -
2019	Ellendale	Leola	45.00	$ 12,014,610	$ 277,778	4,5	20%	$ 2,402,922
2019	Rosebud	Forsyth	11.00	$ 2,402,922	$ 227,273	1	0%	$ -
2019	Watford City	Loop Line	10.00	$ 2,883,506	$ 300,000	4,5	15%	$ 432,526
2019	Bowdle	Whitlock	1.15	$ 216,263	$ 195,652	1	0%	$ -
2019	Dickinson	Loop Line	9.00	$ 2,066,513	$ 238,889	4	0%	$ -
Total			298.74	$ 95,589,707	$ 108,278,077			$ 19,255,321

APPENDIX F:
LOAD FORECAST ON THE TRANSMISSION SYSTEM

Year	Data Source	Transmission System Peak Demand (MW)
2005	Historical[36]	459
2006		485
2007		526
2008		477
2009		474
2010		503
2012		574
2013		560
2014		582
2015		612
2016		597
2017		579
2018	Forecast[37]	606
2019	Forecast[38]	615

[36] FERC Form 1, for the years 2005 through 2017.
[37] MDU IRP
[38] MDU IRP

APPENDIX G:
REVENUE TAX LOADING

Item	Value
MCC Tax Rate	0.046%
PSC Tax Rate	0.244%
Effective Revenue Tax Rate, October 1 2017- September 30, 2018	0.290%

Exhibit No.__(RZ-3)
Page 1.1
Summary Of Marginal Costs By Customer Class and Cost Classification
2019$

Line	Description	Total Energy	Total Demand	Customer	KVAR	Total	Total without KVAR Costs
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e	(g) = b+c+d
1	**Rate / Summary Customer Class**						
2	Residential Rate 10	$ 5,120,689	$ 8,531,721	$ 20,657,865	$ -	$ 34,310,275	$ 34,310,275
3	Small General Primary Rate 20	$ -	$ -	$ -	$ -	$ -	$ -
4	Small General Secondary Rate 20	$ 3,115,943	$ 4,508,737	$ 7,104,238	$ 2,339	$ 14,731,257	$ 14,728,918
6	General Space Heat Rate 32	$ 48,417	$ 70,056	$ 16,611	$ -	$ 135,084	$ 135,084
5	Irrigation Power Rate 25	$ 241,087	$ 784,882	$ 223,802	$ 985	$ 1,250,756	$ 1,249,771
6	Large General Primary Rate 30	$ 1,814,984	$ 3,455,878	$ 26,874	$ 5,636	$ 5,303,372	$ 5,297,736
7	Large General Secondary Rate 30	$ 4,743,271	$ 5,938,606	$ 453,626	$ 11,970	$ 11,147,473	$ 11,135,503
8	Large General Service TOD Rate 31- Secondary	$ 346,711	$ 551,360	$ 3,436	$ 981	$ 902,488	$ 901,507
9	Large General Service TOD Rate 31- Primary	$ 20,962	$ 86,457	$ 10,485	$ 1,993	$ 119,897	$ 117,904
10	Contract Services Rate 35	$ 6,104,509	$ 6,202,150	$ 30,048	$ 197	$ 12,336,904	$ 12,336,707
11	Municipal Pumping Rate 48	$ 189,780	$ 370,390	$ 136,923	$ 1,057	$ 698,150	$ 697,093
12	Outdoor Lighting Rate 52	$ 86,651	$ 125,762	$ 32,548	$ -	$ 244,961	$ 244,961
13	Street Lighting Company Owned Rate 41	$ 58,029	$ 84,216	$ 54,431	$ -	$ 196,676	$ 196,676
14	Street Lighting Municipal Owned Rate 41	$ 18,322	$ 26,629	$ 49,094	$ -	$ 94,045	$ 94,045
15	Total	$ 21,909,355	$ 30,736,844	$ 28,799,981	$ 25,158	$ 81,471,338	$ 81,446,180
16							
17							

MONTANA-DAKOTA UTILITIES CO.
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Exhibit No.__(RZ-1)
Page 1.2
Summary Of Marginal Costs By Customer Class, Season, And Time Of Day
2019$

Line	Description	Summer On Peak	Summer Off Peak	Winter On Peak	Winter Off Peak	Total
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e
1	**Rate / Summary Customer Class**					
2	Residential Rate 10	$ 5,557,970	$ 6,064,814	$ 10,529,482	$ 12,157,997	$ 34,310,263
3	Small General Primary Rate 20	$ -	$ -	$ -	$ (1)	$ (1)
4	Small General Secondary Rate 20	$ 2,607,392	$ 2,397,428	$ 4,950,060	$ 4,776,385	$ 14,731,265
6	General Space Heat Rate 32	$ 30,061	$ 16,347	$ 56,095	$ 32,581	$ 135,084
5	Irrigation Power Rate 25	$ 314,735	$ 246,929	$ 472,944	$ 216,148	$ 1,250,756
6	Large General Primary Rate 30	$ 1,078,812	$ 381,658	$ 2,433,996	$ 1,408,907	$ 5,303,373
7	Large General Secondary Rate 30	$ 2,376,848	$ 1,226,273	$ 4,637,682	$ 2,906,671	$ 11,147,474
8	Large General Service TOD Rate 31- Secondary	$ 171,311	$ 72,902	$ 417,786	$ 240,489	$ 902,488
9	Large General Service TOD Rate 31- Primary	$ 26,348	$ 14,144	$ 51,991	$ 27,414	$ 119,897
10	Contract Services Rate 35	$ 2,630,231	$ 1,610,963	$ 5,041,987	$ 3,053,723	$ 12,336,904
11	Municipal Pumping Rate 48	$ 143,631	$ 97,949	$ 282,047	$ 174,523	$ 698,150
12	Outdoor Lighting Rate 52	$ 39,486	$ 36,454	$ 83,942	$ 85,079	$ 244,961
13	Street Lighting Company Owned Rate 41	$ 30,078	$ 31,571	$ 63,701	$ 71,325	$ 196,675
14	Street Lighting Municipal Owned Rate 41	$ 13,062	$ 17,082	$ 27,213	$ 36,688	$ 94,045
15	Total	$ 15,019,965	$ 12,214,514	$ 29,048,926	$ 25,187,929	$ 81,471,334
16						
17	**Notes**					
18	(1) Generation Energy Costs spread to period based on Plexos results, Generation Demand allocated to Summer and Winter Peak					
19	(2) Non-Generation costs spread to period based on number of hours in period.					

Exhibit No.__(RZ-3)
Summary of the Results of the Marginal Cost Study
Page 2
Summary of Marginal Unit Costs by Function, Classification, Period And Rate Class
2017 $

Line	Description	$ per KWH	$ per KW per Year	$ per Customer per Year	$ per KVAR per Month
	(a)	(b)	(e)	(f)	(g)
1	**Total Energy Related Marginal Cost**				
2	Generation - Average	$ 0.0253			
3	Winter Off-Peak	$ 0.0247			
4	Winter On-Peak	$ 0.0254			
5	Summer Off-Peak	$ 0.0255			
6	Summer On-Peak	$ 0.0284			
7					
8					
9					
10					
11					
12	**Total Capacity Related Marginal Cost**				
13	Generation - Average		$ 135.51		
14	Transmission - Average		$ 26.53		
15	Substation (Transmission) - Average		$ 15.45		
16	Substation (Distribution) - Average		$ 12.52		
17	Distribution (Lines) - Average		$ 16.08		
18	Distribution (Transformers) - Average		$ 1.76		
19					
20					
21	**Reactive Power - Average**				$ 0.59
22					
23	**Total Customer Related Marginal Cost**				
24	Distribution (Lines and Transformers) And Service Lines, Metering, Meter Reading / Billing - Average				
25	Residential Rate 10			$ 1,024.34	
27	Small General Primary Rate 20			$ 1,321.58	
28	Small General Secondary Rate 20			$ 1,235.09	
29	General Space Heat Rate 32			$ 1,107.41	
30	Irrigation Power Rate 25			$ 1,482.13	
32	Large General Primary Rate 30			$ 2,239.51	
33	Large General Secondary Rate 30			$ 1,580.58	
34	Large General TOD Rate 31 -Secondary			$ 1,717.76	
35	Large General TOD Rate 31 -Primary			$ 1,497.88	
36	Contract Services Rate 35			$ 2,311.38	
37	Municipal Pumping Rate 48			$ 1,256.17	
38	Outdoor Lighting Rate 52			$ 1,122.35	
39	Street Lighting Company Owned Rate 41			$ 1,067.27	
40	Street Lighting Municipal Owned Rate 41			$ 1,067.27	
41					
42	**Notes:**				
43	Unit Costs exclude loss adjustments. These unit costs are applied to loss adjusted commodity and demand estimates in order to determine total marginal cost.				

Exhibit No.__(RZ-3)
Page 3
Marginal Energy Costs by Season and Time-of-Use

Line	Description	Calculations	Generation Average Annual	Generation Winter Off-Peak	Generation Winter On-Peak	Generation Summer Off-Peak	Generation Summer On-Peak
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Energy Related Direct Plant - $/KWH	= 6 x 7	$ -	$ -	$ -	$ -	$ -
2	Energy Related Plant (2017 $) - $/KWH	= input	$ -	$ -	$ -	$ -	$ -
3							
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
6	Energy Related Plant (2019 $) - $/KWH	= 3 x 5	$ -	$ -	$ -	$ -	$ -
7	LFCR - %	= input	10.26%	9.40%	9.05%	9.23%	9.73%
8							
9							
10							
11							
12	Energy Related O&M Expense - $/KWH	= 13 x 15	$ 0.02406	$ 0.02354	$ 0.02424	$ 0.02427	$ 0.02722
13	Energy Related O&M Expense (2019 $) - $/KWH	= Exh RZ - 6	$ 0.02406	$ 0.02354	$ 0.02424	$ 0.02427	$ 0.02722
14	Annual Inflation - %	= input	0.00%	0.00%	0.00%	0.00%	0.00%
15	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.000	1.000	1.000	1.000	1.000
16							
17							
18							
19							
20	Energy Related G&A Expense - $/KWH	= 21 x 12	$ -	$ -	$ -	$ -	$ -
21	G&A Loading Factor - %	= input	0.00%	0.00%	0.00%	0.00%	0.00%
22	Energy Related Property Taxes - $/KWH	= 23 x 6	$ -	$ -	$ -	$ -	$ -
23	Effective Property Tax as % of Direct Plant - %	= input	0.2729%	0.2729%	0.2729%	0.2729%	0.2729%
24	Energy Related Generation Taxes - $/KWH	= 25	$ 0.00100	$ 0.00100	$ 0.00100	$ 0.00100	$ 0.00100
25	Generation Tax (Total Effective Rate) - $/KWH	= input	$ 0.00097	$ 0.00097	$ 0.00097	$ 0.00097	$ 0.00097
26	Energy Related Payroll Taxes - $/KWH	= 27 x (12+20)	$ -	$ -	$ -	$ -	$ -
27	Average Payroll Tax As % Of O&M - %	= input	2.29%	2.29%	2.29%	2.29%	2.29%
28	Working Capital Annual Requirement - $/KWH	= 35 x36	$ 0.00010	$ 0.00010	$ 0.00010	$ 0.00010	$ 0.00010
29	Materials And Supplies - $/KWH	= 30 x (6+10)	$ -	$ -	$ -	$ -	$ -
30	Materials And Supplies Factor - %	= input	0.71%	0.71%	0.71%	0.71%	0.71%
31	Prepayments - $/KWH	= 32 x (6+10)	$ -	$ -	$ -	$ -	$ -
32	Prepayments Factor - %	= input	0.06%	0.06%	0.06%	0.06%	0.06%
33	Fuel Stocks - $/KWH	= 34	$ 0.00148	$ 0.00148	$ 0.00148	$ 0.00148	$ 0.00148
34	Fuel Stocks Adder - $/KWH	= input	$ 0.00148	$ 0.00148	$ 0.00148	$ 0.00148	$ 0.00148
35	Total Working Capital - $/KWH	= 29+31+33	$ 0.00148	$ 0.00148	$ 0.00148	$ 0.00148	$ 0.00148
36	Required Return On Working Capital - %	= input		7.54%	7.54%	7.54%	7.54%
37	Total Revenue Related Taxes Marginal Cost - $/KWH	= (1+12+20+26+28) x 38	$ 0.00010	$ 0.00010	$ 0.00010	$ 0.00010	$ 0.00010
38	Revenue-Related Tax Rate - %	= input	0.29%	0.29%	0.29%	0.29%	0.29%
39	Total Energy Related Marginal Cost - $/KWH	= 1+12+20+24+26+28+37	$ 0.02530	$ 0.02470	$ 0.02540	$ 0.02550	$ 0.02840

MONTANA-DAKOTA UTILITIES CO.
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Exhibit No.__(RZ-3)
Page 4
Marginal Capacity Costs

Line	Description	Calculations	Generation	Transmission	Substation (Transmission)	Substation (Distribution)	Distribution (Lines)	Distribution (Transformers)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Capacity Related Direct Plant - $/KW - Yr	= 6 x 7	$108.42	$10.56	$9.01	$10.69	$12.40	$1.38
2	Capacity Related Plant (2017 $) - $/KW	= Exh RZ 6, 7, 8, and 9	$1,163.27	$123.61	$109.68	$127.56	$140.44	$14.47
3								
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040	1.040
6	Capacity Related Plant (2019 $) - $/KW	= 2 x 5 (1)	$1,209.80	$128.56	$114.07	$132.66	$146.06	$15.05
7	LFCR (2) - %	= input	8.96%	8.21%	7.90%	8.06%	8.49%	9.18%
8								
9								
10								
11								
12	Capacity Related O&M Expense - $/KW - Yr	= 13 x 15	$19.54	$12.07	$4.73	$0.91	$2.28	$0.23
13	Capacity Related O&M Expense (2017 $) - $/KW	= input	$18.79	$11.61	$4.54	$0.88	$2.19	$0.22
14	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
15	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040	1.040
16								
17								
18								
19								
20	Capacity Related G&A Expense - $/KW - Yr	= 21 x 12	$5.06	$3.13	$1.23	$0.24	$0.59	$0.06
21	G&A Loading Factor - %	= input	25.92%	25.92%	25.92%	25.92%	25.92%	25.92%
22	Capacity Related Property Taxes - $/KW - Yr	= 23 x 1	0.30	0.13	0.11	0.39	0.45	0.05
23	Effective Property Tax as % of Direct Plant - %	= input	0.00	0.01	0.01	0.04	0.04	0.04
24								
25								
26	Capacity Related Payroll Taxes - $/KW - Yr	= 27 x	0.56	0.35	0.14	0.03	0.07	0.01
27	Average Payroll Tax As % Of O%M - %	= input	2.29%	2.29%	2.29%	2.29%	2.29%	2.29%
28	Working Capital Annual Requirement - $/KW - Yr	= 35 x36	$0.00	$0.08	$0.07	$0.08	$0.09	$0.01
29	Materials And Supplies - $/KW	= 30 x 6	$0.00	$0.92	$0.82	$0.95	$1.05	$0.11
30	Materials And Supplies Factor - %	= input	0.00%	0.71%	0.71%	0.71%	0.71%	0.71%
31	Prepayments - $/KW	= 32 x 6	$0.00	$0.08	$0.07	$0.08	$0.09	$0.01
32	Prepayments Factor - %	= input	0.00%	0.06%	0.06%	0.06%	0.06%	0.06%
33								
34								
35	Total Working Capital - $/KW	= 29+31	$0.00	$1.00	$0.89	$1.03	$1.14	$0.12
36	Required Return On Working Capital - %	= input	7.542%	7.542%	7.542%	7.542%	7.542%	7.542%
37	Total Revenue Related Taxes Marginal Cost - $/KW - Yr	(1+12+20+26 +28) x 38	$0.39	$0.08	$0.04	$0.04	$0.05	$0.00
38	Revenue-Related Tax Rate - %	= input	0.29%	0.29%	0.29%	0.29%	0.29%	0.29%
39	Total Capacity Related Marginal Cost - $/KW - Yr	= 1+12+20+22+ 26+28+37	$135.51	$26.53	$15.45	$12.52	$16.08	$1.76
40	Adjustment for MISO Resource Adequacy Requirements @ 80.7% (Generation Energy Only)		$109.36					
43	**Notes:**							
44	(1) Generation is Line 2 times Line 3 times Line 5. All others are Line 2 times Line 5							

Exhibit No.__(RZ-3)
Page 5
Marginal Customer Costs

	Description	Calculations	Residential Rate 10	Small General Primary Rate 20	Small General Secondary Rate 20	General Space Heat Rate 32	Irrigation Power Rate 25
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 629.84	$ 875.80	$ 774.78	$ 605.45	$ 932.92
2	Customer Related Plant (2017 $) - $/Cust	= Exh RZ 10	$ 5,759.63	$ 8,008.88	$ 7,085.13	$ 5,536.64	$ 8,531.20
3							
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
6	Customer Related Plant (2019 $) - $/Cust	= 3 x 5	$ 5,990.02	$ 8,329.24	$ 7,368.53	$ 5,758.10	$ 8,872.45
7	LFCR - %	= input	10.51%	10.51%	10.51%	10.51%	10.51%
8							
9							
10							
11							
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 104.28	$ 104.28	$ 104.28	$ 104.28	$ 104.28
13	Customer Related O&M Expense (2017 $) - $/Cust	= input	$ 100.27	$ 100.27	$ 100.27	$ 100.27	$ 100.27
14	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
15	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 35.18	$ -	$ 49.14	$ 148.38	$ 81.05
17	Meter Reading, Cust Acct, Svc & Sales Adders (2017 $) - $/Cust	= Exh RZ - 11	$ 33.83	$ -	$ 47.25	$ 142.67	$ 77.93
18	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
19	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 27.03	$ 27.03	$ 27.03	$ 27.03	$ 27.03
21	G&A Loading Factor - %	= input	25.92%	25.92%	25.92%	25.92%	25.92%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 217.76	$ 302.80	$ 267.88	$ 209.33	$ 322.55
23	Effective Property Tax as % of Direct Plant	= input	3.6354%	3.6354%	3.6354%	3.6354%	3.6354%
24							
25							
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 3.81	$ 3.01	$ 4.13	$ 6.40	$ 4.86
27	Average Payroll Tax As % Of O%M - %	= input	2.29%	2.29%	2.29%	2.29%	2.29%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 3.48	$ 4.84	$ 4.28	$ 3.34	$ 5.15
29	Materials And Supplies - $/Cust	= 30 x 6	$ 42.53	$ 59.14	$ 52.32	$ 40.88	$ 62.99
30	Materials And Supplies Factor - %	= input	0.71%	0.71%	0.71%	0.71%	0.71%
31	Prepayments - $/Cust	= 32 x 6	$ 3.59	$ 5.00	$ 4.42	$ 3.45	$ 5.32
32	Prepayments Factor - %	= input	0.06%	0.06%	0.06%	0.06%	0.06%
33							
34							
35	Total Working Capital - $/Cust	= 29+31+33	$ 46.12	$ 64.14	$ 56.74	$ 44.33	$ 68.31
36	Required Return On Working Capital - %	= input	7.54%	7.54%	7.54%	7.54%	7.54%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 2.96	$ 3.82	$ 3.57	$ 3.20	$ 4.29
38	Revenue-Related Tax Rate - %	= input	0.29%	0.29%	0.29%	0.29%	0.29%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,024.34	$ 1,321.58	$ 1,235.09	$ 1,107.41	$ 1,482.13

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	Description	Calculations	Large General Primary Rate 30	Large General Secondary Rate 30	Large General Service TOD Rate 31- Secondary	Large General Service TOD Rate 31- Primary	Contract Services Rate 35
	(a)	(b)	(h)	(i)	(j)	(k)	(l)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 1,293.26	$ 968.92	$ 860.34	$ 878.59	$ 1,335.75
2	Customer Related Plant (2017 $) - $/Cust	= Exh RZ 10	$ 11,826.42	$ 8,860.40	$ 7,867.52	$ 8,034.42	$ 12,215.02
3							
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
6	Customer Related Plant (2019 $) - $/Cust	= 3 x 5	$ 12,299.47	$ 9,214.82	$ 8,182.23	$ 8,355.80	$ 12,703.62
7	LFCR - %	= input	10.51%	10.51%	10.51%	10.51%	10.51%
8							
9							
10							
11							
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 104.28	$ 104.28	$ 104.28	$ 104.28	$ 104.28
13	Customer Related O&M Expense (2017 $) - $/Cust	= input	$ 100.27	$ 100.27	$ 100.27	$ 100.27	$ 100.27
14	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
15	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 343.32	$ 129.46	$ 406.61	$ 168.17	$ 357.24
17	Meter Reading, Cust Acct, Svc & Sales Adders (2017 $) - $/Cust	= Exh RZ - 11	$ 330.12	$ 124.48	$ 390.97	$ 161.70	$ 343.50
18	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
19	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 27.03	$ 27.03	$ 27.03	$ 27.03	$ 27.03
21	G&A Loading Factor - %	= input	25.92%	25.92%	25.92%	25.92%	25.92%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 447.13	$ 335.00	$ 297.46	$ 303.77	$ 461.83
23	Effective Property Tax as % of Direct Plant	= input	3.6354%	3.6354%	3.6354%	3.6354%	3.6354%
24							
25							
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 10.87	$ 5.97	$ 12.32	$ 6.86	$ 11.19
27	Average Payroll Tax As % Of O%M - %	= input	2.29%	2.29%	2.29%	2.29%	2.29%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 7.14	$ 5.35	$ 4.75	$ 4.85	$ 7.38
29	Materials And Supplies - $/Cust	= 30 x 6	$ 87.33	$ 65.43	$ 58.09	$ 59.33	$ 90.20
30	Materials And Supplies Factor - %	= input	0.71%	0.71%	0.71%	0.71%	0.71%
31	Prepayments - $/Cust	= 32 x 6	$ 7.38	$ 5.53	$ 4.91	$ 5.01	$ 7.62
32	Prepayments Factor - %	= input	0.06%	0.06%	0.06%	0.06%	0.06%
33							
34							
35	Total Working Capital - $/Cust	= 29+31+33	$ 94.71	$ 70.96	$ 63.00	$ 64.34	$ 97.82
36	Required Return On Working Capital - %	= input	7.54%	7.54%	7.54%	7.54%	7.54%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 6.48	$ 4.57	$ 4.97	$ 4.33	$ 6.68
38	Revenue-Related Tax Rate - %	= input	0.29%	0.29%	0.29%	0.29%	0.29%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 2,239.51	$ 1,580.58	$ 1,717.76	$ 1,497.88	$ 2,311.38

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	Description	Calculations	Municipal Pumping Rate 48	Outdoor Lighting Rate 52	Street Lighting Company Owned Rate 41	Street Lighting Municipal Owned Rate 41	General Space Heat Rate 32
	(a)	(b)	(m)	(n)	(o)	(p)	(p)
1	Customer Related Direct Plant - $/Cust - Yr	= 6 x 7	$ 772.83	$ 687.73	$ 661.60	$ 661.60	$ 605.45
2	Customer Related Plant (2017 $) - $/Cust	= Exh RZ 10	$ 7,067.30	$ 6,289.02	$ 6,050.12	$ 6,050.12	$ 5,536.64
3							
4	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
5	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
6	Customer Related Plant (2019 $) - $/Cust	= 3 x 5	$ 7,349.99	$ 6,540.58	$ 6,292.12	$ 6,292.12	$ 5,758.10
7	LFCR - %	= input	10.51%	10.51%	10.51%	10.51%	10.51%
8							
9							
10							
11							
12	Customer Related O&M Expense - $/Cust - Yr	= 13 x 15	$ 104.28	$ 104.28	$ 104.28	$ 104.28	$ 104.28
13	Customer Related O&M Expense (2017 $) - $/Cust	= input	$ 100.27	$ 100.27	$ 100.27	$ 100.27	$ 100.27
14	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
15	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
16	Customer Related Meter Reading, Cust Acct, Svc & Sales O&M Expense - $/Cust - Yr	= 17 x 19	$ 72.27	$ 54.23	$ 35.07	$ 35.07	$ 148.38
17	Meter Reading, Cust Acct, Svc & Sales Adders (2017 $) - $/Cust	= Exh RZ - 11	$ 69.49	$ 52.14	$ 33.72	$ 33.72	$ 142.67
18	Annual Inflation - %	= input	2.00%	2.00%	2.00%	2.00%	2.00%
19	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040	1.040	1.040	1.040	1.040
20	Customer Related G&A Expense - $/Cust - Yr	= 21 x 12	$ 27.03	$ 27.03	$ 27.03	$ 27.03	$ 27.03
21	G&A Loading Factor - %	= input	25.92%	25.92%	25.92%	25.92%	25.92%
22	Customer Related Property Taxes - $/Cust - Yr	= 23 x 6	$ 267.20	$ 237.78	$ 228.74	$ 228.74	$ 209.33
23	Effective Property Tax as % of Direct Plant	= input	3.6354%	3.6354%	3.6354%	3.6354%	3.6354%
24							
25							
26	Customer Related Payroll Taxes - $/Cust - Yr	= 27 x (12+16+20)	$ 4.66	$ 4.25	$ 3.81	$ 3.81	$ 6.40
27	Average Payroll Tax As % Of O%M - %	= input	2.29%	2.29%	2.29%	2.29%	2.29%
28	Working Capital Annual Requirement - $/Cust - Yr	= 35 x36	$ 4.27	$ 3.80	$ 3.65	$ 3.65	$ 3.34
29	Materials And Supplies - $/Cust	= 30 x 6	$ 52.18	$ 46.44	$ 44.67	$ 44.67	$ 40.88
30	Materials And Supplies Factor - %	= input	0.71%	0.71%	0.71%	0.71%	0.71%
31	Prepayments - $/Cust	= 32 x 6	$ 4.41	$ 3.92	$ 3.78	$ 3.78	$ 3.45
32	Prepayments Factor - %	= input	0.06%	0.06%	0.06%	0.06%	0.06%
33							
34							
35	Total Working Capital - $/Cust	= 29+31+33	$ 56.59	$ 50.36	$ 48.45	$ 48.45	$ 44.33
36	Required Return On Working Capital - %	= input	7.54%	7.54%	7.54%	7.54%	7.54%
37	Total Revenue Related Taxes Marginal Cost - $/Cust - Yr	= (1+12+16+20+22+26+28) x 38	$ 3.63	$ 3.25	$ 3.09	$ 3.09	$ 3.20
38	Revenue-Related Tax Rate - %	= input	0.29%	0.29%	0.29%	0.29%	0.29%
39	Total Customer Related Marginal Cost - $/Cust - Yr	= 1+12+16+20+22+26+28+37	$ 1,256.17	$ 1,122.35	$ 1,067.27	$ 1,067.27	$ 1,107.41

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Marginal Reactive Power Costs

Line	Description	Calculations	Reactive Power
	(a)	(b)	(c)
1	Reactive Power Related Direct Plant - $/KVAR - Yr	= 6 x 7	$ 6.76
2	Reactive Power Related Plant (2017 $) - $/KVAR		$ 76.63
3			
4	Annual Inflation - %	= input	2.00%
5	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040
6	Reactive Power Related Plant (2019 $) - $/KVAR	= 3 x 5	$ 79.70
7	LFCR - %	= input	8.49%
8			
9			
10			
11			
12	Reactive Power Related O&M Expense - $/KVAR - Yr	= 13 x 15	$ -
13	Reactive Power Related O&M Expense (2017 $) - $/KVAR	= input	$ -
14	Annual Inflation - %	= input	2.00%
15	Inflation Adjustment Rate (2019 $) - Rate	= (1+0.02)^2	1.040
16			
17			
18			
19			
20	Reactive Power Related G&A Expense - $/KVAR - Yr	= 21 x 12	$ -
21	G&A Loading Factor - %	= input	25.92%
22	Reactive Power Related Property Taxes - $/KVAR - Yr	= 23 x 6	$ 0.25
23	Property Tax (Effective Rate) - $/KVAR	= input	3.6354%
24			
25			
26	Reactive Power Related Payroll Taxes - $/KVAR - Yr	= 27 x (12+20)	$ -
27	Average Payroll Tax as % of O&M - %	= input	2.29%
28	Working Capital Annual Requirement - $/KVAR - Yr	= 35 x36	$ 0.05
29	Materials and Supplies - $/KVAR	= 30 x 6	$ 0.57
30	Materials and Supplies Factor - %	= input	0.71%
31	Prepayments - $/KVAR	= 32 x 6	$ 0.05
32	Prepayments Factor - %	= input	0.06%
33			
34			
35	Total Working Capital - $/KVAR	= 29+31+33	$ 0.62
36	Required Return on Working Capital - %	= input	7.542%
37	Total Revenue Related Taxes Marginal Cost - $/KVAR - Yr	= (1+12+20+26+28) x 38	$ 0.02
38	Revenue-Related Tax Rate - %	= input	0.29%
39	Total Reactive Power Related Marginal Cost - $/KVAR - Yr	= 1+12+20+22+26+28+37	$ 7.08

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Marginal Energy Costs

	Description	Average Nominal Energy ($/MWH)	Winter Off-Peak ($/MWH)	Winter On Peak ($/MWH)	Summer Off-Peak ($/MWH)	Summer On Peak ($/MWH)
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Seasonalized Marginal Energy Cost**					
2	Generation Energy Related Cost (Seasonal) - $/MWH	$24.06	$23.54	$24.24	$24.27	$27.22
3	Seasonal Marginal Energy Cost as % of Average Annual Marginal Cost	100.0%	97.8%	100.7%	100.9%	113.1%
4						
5						
6	**Notes:**					
7	(1) Montana Dakota PLEXOS Runs					
8	Soure: 2019 MEC from PLEXOS.xlsx					

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Calcualtion of Incremental Transmisison Investment
2017 $/KW

Summary Marginal Transmisison Investment per KW		
Total Related to Load Growth - $2017 2005-2019		$19,255,321
Change in Transmission Demand (MW)		
2019	614,900	
2005	459,130	
Total Change in Demand		155,770
Total Incremental Marginal Investment (2017$/kW)		**$123.61**

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Calcualtion of Incremental Transmisison and Distribution and Substation Investment
2017 $/KW

Line	Description (a)	MVA (b)		Substation Cost (c)	$ / kW (d) = c / b / 1000
1	Marginal Transmission Substation Plant				
2	Facility				
3	Dickinson West Junction (2014 $)	50	$	5,591,682	$111.83
4	Ray Junction (2014 $)	40	$	5,781,931	$144.55
5	Lignite Junction (2014 $)	40	$	4,652,352	$116.31
6	Williston Little Muddy Junction (2014 $)	50	$	5,433,884	$108.68
7	Collins Trans Sub	18	$	1,438,251	$79.90
8	Mandan Refinery Trans Sub	24	$	2,179,555	$90.81
9	Baker Trans Sub (2016 $)	50	$	2,992,905	$59.86
10	Bowdle Trans Sub (2018 $)	45	$	5,476,800	$121.71
11	Leola Trans Sub (2018 $)	45	$	4,780,674	$106.24
12	Watford City Trans Sub (2018 $)	25	$	5,771,725	$230.87
13	Ellendale 2 Trans Sub (2018 $)	300	$	27,718,300	$92.39
14	Miles City Southwest Trans Sub (2019 $)	45	$	5,462,132	$121.38
15	Dickinson Refinery Trans Sub (2019 $)	30	$	5,500,000	$183.33
16	Total	762	$	82,780,191	$108.64
17	Marginal Distribution Substation Plant				
18	Facility				
19	Bismarck 26th St & Ave D Dist Sub (2014 $)	15	$	1,876,950	$125.13
20	Williston Water Plant Dist Sub (2014 $)	5	$	621,139	$124.23
21	Dickinson West Dist Sub (2014 $)	10	$	879,660	$87.97
22	Epping Dist Sub (2014 $)	3.75	$	595,195	$158.72
23	Mandan Collins Dist Sub (2015 $)	18	$	1,947,558	$108.20
24	Wishek Dist Sub (2016 $)	5	$	532,040	$106.41
25	Williston Halliburton Dist Sub (2016 $)	7.5	$	719,110	$95.88
26	Williston Oasis Dist Sub (2016 $)	7.5	$	776,967	$103.60
27	Bismarck South 9th St Dist Sub (2017 $)	18	$	2,210,115	$122.78
28	Heil Dist Sub (2018 $)	2	$	349,331	$174.67
29	Leola Dist Sub (2018 $)	2.5	$	253,852	$101.54
30	Dickinson North Dist Sub (2019 $)	10	$	1,585,344	$158.53
31	Keystone Dist Sub (2019 $)	20	$	3,054,359	$152.72
32	Total	124.3	$	15,401,620	$123.96

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Calcualtion of Incremental Distribution Line and Transformer Investment
2017 $/KW

Line	Description	Number of Customers	# Circuits	Customers per Circuit	OH Miles	UG Miles	OH $/Mile (1)	UG $/Mile (1)	Total ($/Customer)	Demand Related ($/Customer)	Customer Related ($/Customer)
	(a)	(b)	(c)	(d) = b/d	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Marginal Distribution Capacity Related Plant Cost - Lines										
2	Facility										
3	Glendive District	20,400	95	215	2,073.3	484.2	$ 38,030	$ 74,620	$ 5,636.21	$ 1,008.26	$ 4,627.95
4	Wolf Point District	7,355	53	139	899.5	159.1	$ 38,030	$ 74,620	$ 6,265.13	$ 1,143.46	$ 5,121.67
5	Total	27,755	148	188	2,972.8	643.3	$ 38,030	$ 74,620	$ 5,802.87	$ 1,044.08	$ 4,758.79
6											
7	Capacity related distribution line cost per NCP KW - Primary and Secondary (2)									$ 140.44	
8											
9											
10											
11								Number of Customers	Total Cost (1)	Cost per KW	
12	Marginal Distribution Capacity Related Plant Cost - Transformers							(l)	(m)	(n)	
13	Facility										
14	Single Phase Transformers							26,089	$ 376,490	$ 14.43	
15	Three Phase Transformers							771	$ 12,124	$ 15.73	
16	Capacity related distribution transformer cost per NCP KW @ meter - Secondary Only							26,860	$ 388,614	$ 14.47	
17											
18											
19											
20											
21										Cost Per KW	
22										(o) = line 7 column j + line 16 column n	
23	Total Capacity Related Distribution Plant Costs Per NCP KW - Primary									$ 140.44	
24	Total Capacity Related Distribution Plant Costs Per NCP KW - Secondary									$ 154.91	
25											
26	**Notes:**										
30	(2) Total demand related cost per customer times total number of customers in Montana divided by Total NCP Load in Montana.										

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Customer Related Distribution (Lines and Transformers), Service Lines and Metering Plant Cost
2017$

Costs by Function, Plant Type and Rate Class (1)

		Distribution		Service Lines, Metering, Meter Reading / Billing		
Line	**Description**	**Transformers FERC Account 368**	**Distribution Lines FERC Account 363-367**	**Services FERC Account 369**	**Meters FERC Account 370 (5)**	**Total Customer Plant**
	(a)	(b)	(c)	(d)	(e)	(f) = b+c+d+e
1	Rate Class					
2	Residential Rate 10	$ 229.18	$ 4,758.79	$ 680.22	$ 91.44	$ 5,759.63
4	Small General Primary Rate 20	$ -	$ 4,758.79	$ -	$ 3,250.09	$ 8,008.88
5	Small General Secondary Rate 20	$ 1,589.76	$ 4,758.79	$ 529.13	$ 207.44	$ 7,085.13
6	General Space Heat Rate 32	$ -	$ 4,758.79	$ -	$ 777.85	$ 5,536.64
7	Irrigation Power Rate 25	$ 2,513.15	$ 4,758.79	$ 885.84	$ 373.42	$ 8,531.20
10	Large General Primary Rate 30	$ -	$ 4,758.79	$ -	$ 7,067.63	$ 11,826.42
11	Large General Secondary Rate 30	$ 1,924.17	$ 4,758.79	$ 1,066.22	$ 1,111.23	$ 8,860.40
12	Large General Service TOD Rate 31-Secondary	$ 1,405.25	$ 4,758.79	$ 1,106.97	$ 596.52	$ 7,867.52
13	Large General Service TOD Rate 31-Primary	$ -	$ 4,758.79	$ -	$ 3,275.63	$ 8,034.42
14	Contract Services Rate 35	$ -	$ 4,758.79	$ -	$ 7,456.23	$ 12,215.02
15	Municipal Pumping Rate 48	$ 1,095.21	$ 4,758.79	$ 698.02	$ 515.28	$ 7,067.30
16	Outdoor Lighting Rate 52	$ 873.81	$ 4,758.79	$ -	$ 656.42	$ 6,289.02
17	Street Lighting Company Owned Rate 41	$ 873.81	$ 4,758.79	$ 327.30	$ 90.21	$ 6,050.12
18	Street Lighting Municipal Owned Rate 41	$ 873.81	$ 4,758.79	$ 327.30	$ 90.21	$ 6,050.12

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Meter Reading, Customer Accounting, Customer Service and Sales Expense Related Marginal Cost Adders
2017$

Line	Description	
	(a)	(b)
1	Marginal Related Customer Accounts Expense (Current $)	$ 828,172
2	Supervision	$ 27,459
3	Meter Reading Expense	$ 83,819
4	Customer Records and Collection Exp.	$ 511,731
5	Uncollectible Accounts	$ 144,799
6	Misc. Customer Accounts Expense	$ 60,364
7	Total Customer Accounts Expense	$ 828,172
8	Marginal Related Customer Service & Info Expense (Current $)	$ 45,520
9	Supervision	$ 8,912
10	Customer Assistance Expense	$ 8,129
11	Informational and Instructional Expense	$ 28,479
12	Misc. Customer Service & Info. Exp.	$ -
13	Total Customer Service & Info. Exp.	$ 45,520
14	Marginal Related Sales Expense (Current $)	$ 27,552
15	Supervision	$ 300
16	Demonstrating and Selling Expense	$ 22,700
17	Advertising Expense	$ 1,731
18	Misc. Sales Expense	$ 2,821
19	Total Sales Expense	$ 27,552
20	Marginal Cust Acct, Svc & Sales Expense (Current $)	$ 901,244
21		
22	Handy-Whitman Factor for Distribution Plant	1.0000
23		
24	Marginal Cust Acct, Svc & Sales Expense (2017 $)	$ 901,244
25		
26	Total Number of Customers	26,641
27		
28	Total Marginal Customer Account, Services & Sales O&M Expense (2017 $)	$ 33.83

Marginal Unit Cost Per Customer

Line	Description	Meter Reading Expense	Customer Accounts Expense	Service & Info Expense	Sales Expense	Total
	(h)	(h) = h * class weight	(i) = i * class weight	(j) = j * class weight	(k) = k * class weight	(l) = h+i+j+k
29	Marginal Unit Cost Per Customer	$ 3.15	$ 27.94	$ 1.71	$ 1.03	$ 33.83
30	Weighted Marginal Cost Per Customer Per Rate Class					
31	Residential Rate 10	$ 3.15	$ 27.94	$ 1.71	$ 1.03	$ 33.83
32	Small General Primary Rate 20	$ -	$ -	$ -	$ -	$ -
33	Small General Secondary Rate 20	$ 7.14	$ 36.88	$ 1.86	$ 1.37	$ 47.25
34	General Space Heat Rate 32	$ 26.77	$ 111.76	$ -	$ 4.14	$ 142.67
35	Irrigation Power Rate 25	$ 12.84	$ 60.63	$ 2.22	$ 2.24	$ 77.93
36	Large General Primary Rate 30	$ 243.20	$ 83.82	$ -	$ 3.10	$ 330.12
37	Large General Secondary Rate 30	$ 38.23	$ 80.47	$ 2.80	$ 2.98	$ 124.48
38	Large General Service TOD Rate 31- Secondary	$ 217.12	$ 167.64	$ -	$ 6.21	$ 390.97
39	Large General Service TOD Rate 31- Primary	$ 27.25	$ 127.69	$ 2.03	$ 4.73	$ 161.70
40	Contract Services Rate 35	$ 256.58	$ 83.82	$ -	$ 3.10	$ 343.50
41	Municipal Pumping Rate 48	$ 14.13	$ 51.69	$ 1.76	$ 1.91	$ 69.49
42	Private Lighting Rate 52	$ 22.59	$ 28.50	$ -	$ 1.05	$ 52.14
43	Street Lighting Company Owned Rate 41	$ 3.11	$ 27.94	$ 1.64	$ 1.03	$ 33.72
44	Street Lighting Municipal Owned Rate 41	$ 3.11	$ 27.94	$ 1.64	$ 1.03	$ 33.72

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46 **Notes:**
47 (1) Actual Account Balances
48 (2) Actual Customer Counts
49 (3) Class Weights from Embedded Class Cost of Service Study
50 (4) 2017 $ unless otherwise indicated

MONTANA-DAKOTA UTILITIES CO.

A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2018.9.___

Direct Testimony
of
Stephanie Bosch

Q. Would you please state your name and business address?

A. Yes. My name is Stephanie Bosch, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Would you please describe your duties as Regulatory Affairs Manager?

A. I am responsible for the proper application of the Company's gas and electric rates in the Customer Care and Billing System (CC&B), the application of tariffs, and the preparation of miscellaneous rate filings.

Q. Would you please describe your education and professional background?

A. I graduated from the University of North Dakota in 1995 with a Bachelor of Business and Public Administration degree in Banking and Financial Economics. I joined Montana-Dakota in June 1997 as a Rate Clerk in the Regulatory Affairs Department and realized positions of increasing responsibility within the Regulatory Affairs Department until 2011 when I left the Company. In 2013 I returned to the Company as a Regulatory Analyst before attaining my current position in August of 2015.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the pro forma electric revenues at current rates, included in Statement H of this Application and the proposed rate schedules provided in Appendix B to the Application

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and the Public Service Commissions of North Dakota and Wyoming.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring the proposed rate schedules provided in Appendix B to the Application, with the exception of the proposed Fuel and Purchased Power Cost Tracking Adjustment Rate 58, which is sponsored by Mr. Jacobson.

I am also sponsoring the proposed interim rate schedules provided in Appendix A to the Interim Application.

Q. Would you please explain the calculation of the revenue at current rates included in Statement H?

A. Yes. The Company applied the Basic Service Charges, Energy Charges, and Demand Charges applicable under each rate schedule, and as authorized in Docket No. D2015.6.51, as well as the pro forma Fuel and Purchased Power rates, to the actual 2017 billing determinants with the following three adjustments: (1) the Rate 20 primary service pro forma billing determinants were set to zero to reflect that no customers are currently taking primary service under Rate 20, (2) the billing determinants of a Rate 30 primary service customer were reclassified as Rate 35 service to reflect the customer’s current rate, and (3) a reduction in the usage under Municipal Lighting Service Rate 41 resulting from the Company’s 2018 LED street lighting project.

The current tax tracking adjustment rate of 7.8407% was then applied to the resulting revenue, excluding fuel.

Q. Would you please explain further the reduction reflected in the pro forma Kwh for the Municipal Lighting Service Rate 41?

A. In 2018, the Company completed an LED street lighting replacement project for Company-owned municipal lighting facilities in the state of Montana. Older Company-owned street lighting fixtures were replaced with LED street lighting fixtures in all Montana communities resulting in energy and maintenance savings and higher lumen output. This replacement was also prompted in part by the trend toward less availability of older lighting fixtures. The project was not applicable to street lighting facilities owned by the customer.

While the total number of Rate 41 customers remains unchanged by the project, the energy used by these new lighting facilities is noticeably less from that of the 2017 per books level. To ascertain the pro forma Kwh for this rate case and the resulting Kwh savings resulting from this project, a query was run against the Company's Customer Care & Billing system to identify the number of lighting facilities installed by LED lighting type for each Rate 41 customer upon completion of the street lighting project. Using those counts and the daily consumption applicable for each LED lighting type, the Company is able to determine the annual consumption for all Company-owned Rate 41 customers.

The Kwh applicable to all other Rate 41 customers remains unchanged from the 2017 per books level.

Q. The Company is proposing a number of changes to its Municipal Lighting Service Rate 41 tariff? Could you outline the proposed changes?

A. Yes, I will briefly summarize the proposed changes:

- Expand the availability of the tariff to include the lighting of all public streets, alleys, and other road right of ways, and to no longer limit the availability to those lighting facilities owned by a municipality. This expansion of availability then necessitates a change to the title of the tariff to Public Lighting Service Rate 41.
- Include on the Rate 41 tariff the monthly Facilities Charges applicable to lighting facilities owned, installed, and maintained by the Company. While these “rental type” charges are not new to the Company or the customer being billed the charges today, the Company has not previously included the charges on the Rate 41 tariff. The street lighting project afforded the Company the ability to standardize across the state of Montana the lighting facilities the Company will now install and maintain for the customer and the associated monthly rate applicable for such facilities. These charges are not applicable to lighting facilities owned by the customer and/or municipality.

- Clarify the determination of the monthly energy usage when the lighting service is un-metered. Consistent with all other customers, un-metered Rate 41 customers are billed monthly; however, the determination of that monthly energy usage is computed using a daily consumption level times the number of days in a customer's billing period.

Q. Would you please explain why the Company is proposing to eliminate Optional Residential Electric Thermal Energy Storage Rate 13?

A. Yes. Optional Residential Electric Thermal Energy Storage Rate 13 was initially introduced in the Company's 2010 electric rate case. The tariff provided an optional rate to residential customers with electric space heating requirements that had, or were planning to install, a thermal storage system that used electricity during the Company's off peak hours and then stored that energy for use during the remaining hours. The rate first became available to customers in September 2011.

Since its introduction seven years ago, no customers have taken service under the optional rate in Montana and there has been no recent interest in the rate. Therefore the Company is proposing to eliminate Rate 13 from its electric tariff.

Q. Please describe any additional changes the Company is proposing to its electric tariffs?

A. Yes. Montana-Dakota is proposing the following changes to the Company's electric tariffs as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- The rates described by Mr. Hatzenbuhler have been incorporated into the proposed tariffs.
- Increase the Returned Check Charge to $30.
- Introduce a monthly Manual Meter Reading Charge assessed customers who request to have their electric meter read manually each month in lieu of the Company installing an AMR-equipped meter to obtain meter reads.
- Revise the Employee Discount to reflect the applicability to qualifying retirees only of MDU Resources and its subsidiaries.
- There are other wording changes listed throughout the rate to improve the readability of the rate without modifying any conditions. These changes are clearly denoted on the tariff sheets in the legislative format.

Q. Does this conclude your testimony?

A. Yes.