THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
ALLETE, Inc.	End of 2018/Q4

Report of Independent Auditors

To Management and the Board of Directors of ALLETE, Inc.:

We have audited the accompanying financial statements of ALLETE, Inc. which comprise the balance sheets as of December 31, 2018 and December 31, 2017, and the related statements of income, retained earnings, and cash flows for the years then ended, included on pages 110 through 121 of the accompanying Federal Energy Regulatory Commission Form 1.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 19. Management is also responsible for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of ALLETE, Inc. as of December 31, 2018 and December 31, 2017, and the results of its operations and its cash flows for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 19.

PricewaterhouseCoopers LLP, Suite 3400, 45 South 7th Street, Minneapolis, MN 55402
T: (612) 596 6000, F: (612) 373 7160, www.pwc.com/us

Basis of Accounting

We draw attention to Note 19 of the financial statements, which describes the basis of accounting. As described in Note 19 to the financial statements, the financial statements are prepared by ALLETE, Inc. on the basis of the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America, to meet the requirements of the Federal Energy Regulatory Commission. Our opinion is not modified with respect to this matter.

Restriction of Use

This report is intended solely for the information and use of the Board of Directors and Management of ALLETE, Inc. and for the filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

PricewaterhouseCoopers LLP

Minneapolis, Minnesota
April 17, 2019

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent ALLETE, Inc.	02 Year/Period of Report End of 2018/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 30 West Superior Street, Duluth, MN 55802	
05 Name of Contact Person Joshua G. Rostollan	06 Title of Contact Person Supervisor - Accounting
07 Address of Contact Person *(Street, City, State, Zip Code)* 30 West Superior Street, Duluth, MN 55802	

08 Telephone of Contact Person, *Including Area Code* (218) 355-3151	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Steven W. Morris 02 Title VP, Controller, Chief Acctg Officer	03 Signature	04 Date Signed *(Mo, Da, Yr)* 04/17/2019

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Steven W. Morris - Vice President, Controller and Chief Accounting Officer
30 West Superior Street
Duluth, MN 55802

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated/Reorganized under Minnesota law as Minnesota Power & Light Company on October 26, 1923, and renamed Minnesota Power, Inc. on May 27, 1998. Corporate name changed to ALLETE, Inc. effective May 8, 2001.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric Utility - Minnesota

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	ALLETE Automotive Services, LLC	Administrative Operations	100	1
3	ALLETE Enterprises, Inc.	Holding Company	100	1
4	ALLETE Clean Energy, Inc.	Holding Company	100	7
5	ACE Wind LLC	Holding Company	100	8
6	ACE Mid-West Holdings, LLC	Holding Company	100	9
7	MWW Holdings, LLC	Holding Company	100	10
8	Lake Benton Power Associates LLC	Holding Company	100	11
9	Lake Benton Holdings LLC	Holding Company	100	12
10	Lake Benton Power Partners L.L.C.	Electric and Other Services	100	13
11	Storm Lake Power Partners I LLC	Electric and Other Services	100	11
12	Storm Lake II Power Associates LLC	Holding Company	100	11
13	Storm Lake II Holdings LLC	Holding Company	100	14
14	Storm Lake Power Partners II LLC	Electric and Other Services	100	15
15	New Salem Holdings, LLC	Holding Company	100	11
16	Glen Ullin Energy Center, LLC	Electric and Other Services	100	16
17	Northern Wind Energy, LLC	Holding Company	100	10
18	Chanarambie Power Partners, LLC	Electric and Other Services	100	20
19	Viking Wind Holdings, LLC	Electric and Other Services	100	20
20	ACE West Holdings, LLC	Holding Company	100	9
21	Condon Wind Power, LLC	Electric and Other Services	100	17
22	South Peak Wind LLC	Electric and Other Services	100	17
23	Armenia Holdings, LLC	Holding Company	100	9
24	AMW I Holding, LLC	Holding Company	100	21
25	Armenia Mountain Wind, LLC	Electric and Other Services	100	22
26	Armenia Mountain Wind II, LLC	Electric and Other Services	100	21
27	Thunder Spirit Wind, LLC	Electric and Other Services	100	9

CORPORATIONS CONTROLLED BY RESPONDENT

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	ACE O&M, LLC	Electric and Other Services	100	8
2	ALLETE Power Systems, Inc.	Electric and Other Services	100	7
3	ALLETE Renewable Resources, Inc.	Administrative Operations	100	7
4	ALLETE South Wind, LLC	Holding Company	100	7
5	ALLETE Transmission Holdings, Inc.	Investments	100	7, 19
6	BNI Energy, Inc.	Holding Company	100	7
7	BNI Coal, Ltd.	Coal Mining	100	25
8	Global Water Services Holding Company, Inc.	Holding Company	98	7
9	U.S. Water Services, Inc.	Water & Wastewater Treatment	100	23
10	U.S. Water Services - Canada, Inc.	Water & Wastewater Treatment	100	24
11	USWATERSERV-DR, S.R.L.	Water & Wastewater Treatment	100	24
12	MP Affiliate Resources, Inc.	Administrative Operations	100	7
13	Rainy River Energy Corporation	Generation/Power Marketing	100	7
14	South Shore Energy, LLC	Investments	100	7
15	Upper Minnesota Properties, Inc.	Afford Housing Proj/Econ Dev	100	7
16	Upper Minnesota Properties - Development, Inc.	Economic Development	100	18
17	ALLETE Properties, LLC	Real Estate	100	1
18	ALLETE Commercial, LLC	Real Estate	100	2
19	Lehigh Acquisition, LLC	Real Estate	100	2
20	Florida Landmark Communities, LLC	Subdivider, Developer	100	3
21	Lehigh Corporation	Real Estate	100	4
22	Mardem, LLC	Real Estate	100	4
23	Palm Coast Holdings, Inc.	Real Estate	100	4
24	Port Orange Holdings, LLC	Real Estate	100	4
25	Interlachen Lakes Estates, LLC	Real Estate	100	3
26	Palm Coast Land, LLC	Subdivider, Developer	100	2
27	ALLETE Water Services, Inc.	Administrative Operations	100	1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Florida Water Services Corporation	Water & Wastewater Treatment	100	5
2	Energy Replacement Property, LLC	Real Estate	100	6
3	Energy Land, Incorporated	Inactive	100	1
4	Lakeview Financial Corporation I	Financial Services	100	1
5	Lakeview Financial Corporation II	Inactive	100	1
6	MP Investments, Inc.	Investments	100	1
7	RendField Land Company, Inc.	Real Estate	100	1
8	Superior Water, Light and Power Company	Electric, Gas & Water Utility	100	1
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Schedule Page: 103   Line No.: 1   Column: d

1. Subsidiary of ALLETE, Inc.
2. Subsidiary of ALLETE Properties, LLC
3. Subsidiary of Lehigh Acquisition, LLC
4. Subsidiary of Florida Landmark Communities, LLC
5. Subsidiary of ALLETE Water Services, Inc.
6. Subsidiary of Florida Water Services Corporation
7. Subsidiary of ALLETE Enterprises, Inc.
8. Subsidiary of ALLETE Clean Energy, Inc.
9. Subsidiary of ACE Wind, LLC
10. Subsidiary of ACE Mid-West Holdings, LLC
11. Subsidiary of MWW Holdings, LLC
12. Subsidiary of Lake Benton Power Associates LLC
13. Subsidiary of Lake Benton Holdings LLC
14. Subsidiary of Storm Lake II Power Associates LLC
15. Subsidiary of Storm Lake II Holdings LLC
16. Subsidiary of New Salem Holdings, LLC
17. Subsidiary of ACE West Holdings, LLC
18. Subsidiary of Upper Minnesota Properties, Inc.
19. ALLETE Transmission Holdings, Inc. has a 7.77 percent ownership in American Transmission Company, LLC as of December 31, 2018.
20. Subsidiary of Northern Wind Energy, LLC
21. Subsidiary of Armenia Holdings, LLC
22. Subsidiary of AMW I Holdings, LLC
23. Subsidiary of Global Water Services Holding Company, Inc.
24. Subsidiary of U.S. Water Services, Inc.
25. Subsidiary of BNI Energy, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
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2	Please refer to the 'Executive Compensation Tables'		
3	information in the Footnote Data of this page 104.		
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Schedule Page: 104 Line No.: 2 Column: a

EXECUTIVE COMPENSATION TABLES

The following table sets forth information for the last three fiscal years. Information for fiscal years 2016 is not provided for Ms. Owen because she was not an NEO prior to fiscal year 2017. Information for fiscal years 2016 and 2017 is not provided for Mr. Mullen because he was not an NEO prior to fiscal year 2018.

Summary Compensation Table

(a) Name and Principal Position[1]	(b) Year	(c) Salary	(d) Stock Awards[2]	(e) Non-Equity Incentive Plan Compensation[3]	(f) Change in Pension Value[4]	(g) All Other Compensation[5]	(h) Total
Alan R. Hodnik	2018	$633,421	$1,291,261	$726,906	$709,665	$132,205	$3,493,458
Chairman and Chief Executive Officer	2017	$623,574	$1,130,234	$729,626	$868,081	$112,568	$3,464,083
	2016	$613,584	$999,067	$436,029	$602,455	$127,303	$2,778,438
Robert J. Adams	2018	$357,870	$361,578	$246,413	$175,938	$71,332	$1,213,131
Senior Vice President and Chief	2017	$327,456	$248,653	$212,296	$200,894	$51,177	$1,040,476
Financial Officer	2016	$282,454	$142,745	$108,512	$119,353	$50,197	$703,261
Bradley W. Oachs	2018	$381,090	$309,947	$219,373	$225,305	$71,868	$1,207,583
Senior Vice President and President	2017	$351,870	$226,059	$194,400	$226,991	$63,311	$1,062,631
Regulated Operations	2016	$292,780	$142,745	$128,816	$43,809	$47,150	$655,300
Deborah A. Amberg	2018	$315,685	$258,316	$121,164	$217,627	$615,798	$1,527,590
Former Senior Vice President and Chief	2017	$344,867	$203,404	$133,980	$173,867	$54,483	$910,601
Strategy Officer Regulated Operations	2016	$338,731	$214,119	$130,911	$116,123	$57,499	$857,383
Bethany M. Owen	2018	$295,888	$284,088	$169,779	$49,454	$52,732	$851,941
President	2017	$268,956	$203,404	$140,421	$45,838	$43,309	$701,928
Patrick K. Mullen	2018	$256,728	$154,894	$132,578	$50,259	$53,715	$648,174
Senior Vice President External Affairs							

1 The principal positions are as of March 15, 2019. On January 31, 2019, the Board elected Ms. Owen as ALLETE's President. Prior to that date, and throughout 2018, Ms. Owen served as Senior Vice President, Chief Legal and Administrative Officer, and Secretary, and Mr. Hodnik was ALLETE's Chairman, President, and CEO.

2 The amounts shown in column (d) represent the actuarial value of the future payout, but are not amounts that were paid to the NEOs in the year reported. The actual amount that an NEO will earn will depend on the extent to which long-term incentive goals are achieved and on the then-current market price of Common Stock. The actual value each NEO realized in 2018 from stock awards in prior years is shown in the "Option Exercises and Stock Vested" table on page 53 of ALLETE's 2019 Proxy Statement for the 2019 Annual Meeting of Shareholders. The amounts in column (d) relate to PSA and RSU opportunities awarded to the NEOs during 2018. The amounts shown reflect the grant date fair value determined in accordance with generally accepted accounting principles under ASC 718, using the same assumptions used in the valuation of compensation expenses disclosed in Note 16 to the Company's Consolidated Financial Statements contained in the 2018 Annual Report on Form 10-K, but based on a modeled probability of reaching performance goals and excluding the effect of estimated forfeitures. This estimated value was calculated by our consultant Mercer using a Monte-Carlo simulation model that used an underlying Black-Scholes methodology. The grant date fair value is the total amount that we will recognize as an expense over the awards' vesting period, except that the amounts shown do not include a reduction for forfeitures. The amounts shown in column (d) for 2018 are comprised of the following:

	RSUs	PSAs*
Alan R. Hodnik	$303,120	$988,141
Robert J. Adams	$84,885	$276,693
Bradley W. Oachs	$72,769	$237,178
Deborah A. Amberg	$60,653	$197,663
Bethany M. Owen	$66,711	$217,377
Patrick K. Mullen	$36,348	$118,546

* The maximum grant date fair value for each NEO's unearned 2018 PSAs, assuming the highest level of performance were to be achieved, is as follows: Mr. Hodnik—$1,976,282, Mr. Adams—$553,386,
Mr. Oachs—$474,356, Ms. Owen—$434,754, Mr. Mullen—$237,092, and Ms. Amberg—$395,326.

3 The amounts in column (e) reflect annual incentive awards earned in 2018 and paid in 2019. The amounts shown include any portion of the award that was deferred at the NEO's election. Ms. Amberg's award was prorated to reflect her separation from service on November 28, 2018.

4 The amounts shown in column (f) represent the actuarial increase during 2018 in the value of retirement benefits earned by each NEO under our retirement plans, which are described beginning on page 54 of ALLETE's 2019 Proxy Statement for the 2019 Annual Meeting of Shareholders, and were not paid to the NEOs in the year reported.

5 The amounts in column (g) for 2018 are comprised of the following:

	Company RSOP Contributions, Flexible Compensation Benefits, and Life Insurance Premiums	Company Contributions Under SERP II	Acceleration of Outstanding Equity Awards in Connection with Retirement*	Payments in Connection with Separation from Service**
Alan R. Hodnik	$50,783	$81,422	—	—
Robert J. Adams	$49,297	$22,035	—	—
Bradley W. Oachs	$49,405	$22,463	—	—
Deborah A. Amberg	$40,536	$15,200	$163,693	$396,369
Bethany M. Owen	$40,719	$12,013	—	—
Patrick K. Mullen	$45,148	$8,567	—	—

*Ms. Amberg's employment ended on November 28, 2018, resulting in an accelerated vesting of the following outstanding RSU grants: 1,183 RSUs granted in January 2016, 593 RSUs granted in January 2017, and 265 RSUs granted in January 2018. Dividend equivalent shares also vested in connection with each grant. Ms. Amberg's receipt of these shares is subject to a non-elective, six-month deferral. The value of the accelerated vesting was calculated by multiplying the exact (non-rounded) number of shares acquired on vesting by the closing price of Common Stock on November 28, 2018.

**Amount shown was paid or accrued in connection with a separation agreement between the Company and Ms. Amberg as follows: (1) a lump-sum payment of $344,866; (2) $36,503 for 18 months of Company-paid health care premiums and life insurance premiums, of which $7,916 is for amounts actually paid through March 2019, and the remainder reflects a reasonable estimate of the additional amounts to be paid; (3) $10,000 for outplacement services; and (4) $5,000 for tax consulting and financial planning services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Kathryn W. Dindo	Akron, OH
2		
3	Sidney W. Emery, Jr.	Minneapolis, MN
4		
5	George G. Goldfarb	Duluth, MN
6		
7	James S. Haines, Jr.***	Lawrence, KS
8		
9	Alan R. Hodnik	Duluth, MN
10	Chief Executive Officer	
11	Chairman	
12		
13	James J. Hoolihan***	Grand Rapids, MN
14		
15	Heidi E. Jimmerson***	St. Augustine, FL
16		
17	Madeleine W. Ludlow**	Cincinnati, OH
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19	Susan K. Nestegard	Austin, TX
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21	Douglas C. Neve***	Bonita Springs, FL
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23	Robert P. Powers	Denver, CO
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25	Leonard C. Rodman***	Olathe, KS
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Market-Based Formula Rates	ER18-521-000
2	FERC Electric Tariff No. 205	ER13-1331-000
3	FERC Electric Tariff No. 182	ER17-169-000
4	FERC Electric Tariff No. 186	ER17-1147-000
5	FERC Electric Tariff No. 187	ER17-1148-000
6	FERC Electric Tariff No. 188	ER17-1149-000
7	FERC Electric Tariff No. 189	ER17-1150-000
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Schedule Page: 106 Line No.: 1 Column: b

Market-Based Formula Rates

On December 23, 2017, FERC Docket No. ER18-521-000 superseded FERC Docket No. ER15-772-000 which had an effective date of March 1, 2015. Full requirement municipal customers' rates were calculated based on standardized power supply formula rate contracts based on the FERC Form 1. The contracts, which have effective dates of April 1, 2013, July 1, 2013, September 1, 2015, or August 1, 2017, were executed under ALLETE's market-based rate (MBR) authority. These MBR contract agreements do not require a FERC filing. ALLETE reports the required contract and transaction information related to the agreements in ALLETE's quarterly reports.

Schedule Page: 106 Line No.: 2 Column: b

FERC Electric Tariff No. 205

In FERC Docket No. ER13-1331-000, ALLETE submitted a Facilities Construction Agreement (FCA) among ALLETE, the Nashwauk Public Utilities Commission, and Mesabi Metallics Company LLC (formerly Essar Steel Minnesota LLC). ALLETE has designated the FCA as FERC Electric Tariff No. 205. The FCA became effective June 23, 2013.

Schedule Page: 106 Line No.: 3 Column: b

FERC Electric Tariff No. 182

In FERC Docket No. ER17-169-000, ALLETE submitted a Maintenance Services Agreement (MSA) for certain transmission substation facilities among ALLETE and Northern States Power Company. ALLETE has designated the MSA as FERC Electric Tariff No. 182. The MSA became effective December 23, 2016.

Schedule Page: 106 Line No.: 4 Column: b

FERC Electric Tariff No. 186

In FERC Docket No. ER17-1147-000, ALLETE submitted a Construction Management Agreement (CMA) among ALLETE and a subsidiary of Manitoba Hydro for the rights and obligations concerning the construction management services for the Great Northern Transmission Line. ALLETE has designated the CMA as FERC Electric Tariff No. 186. The CMA became effective May 10, 2017.

Schedule Page: 106 Line No.: 5 Column: b

FERC Electric Tariff No. 187

In FERC Docket No. ER17-1148-000, ALLETE submitted a Transmission Capacity Exchange Agreement (TCEA) among ALLETE and a subsidiary of Manitoba Hydro for the rights and obligations relative to the transmission capacity of the Great Northern Transmission Line once it goes into service. ALLETE has designated the TCEA as FERC Electric Tariff No. 187. The TCEA became effective May 10, 2017.

Schedule Page: 106 Line No.: 6 Column: b

FERC Electric Tariff No. 188

In FERC Docket No. ER17-1149-000, ALLETE submitted an Operation and Maintenance Agreement (OMA) among ALLETE and a subsidiary of Manitoba Hydro that governs the rights and obligations concerning the operation and maintenance of the Great Northern Transmission Line. ALLETE has designated the OMA as FERC Electric Tariff No. 188. The OMA became effective May 10, 2017.

Schedule Page: 106 Line No.: 7 Column: b

FERC Electric Tariff No. 189

In FERC Docket No. ER17-1150-000, ALLETE submitted a System Improvements Agreement (SIA) among ALLETE and a subsidiary of Manitoba Hydro for system improvements determined necessary to support ALLETE's transmission system after the Great Northern Transmission Line goes into service. ALLETE has designated the SIA as FERC Electric Tariff No. 189. The SIA became effective May 10, 2017.

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20180411-8001	04/06/2018	None	2017 FERC Form 1	N/A
2					
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Abbreviations and acronyms used in the text are defined beginning on page 123.76 of this FERC Form 1. References in this report to "we", "us" and "our" are to ALLETE, Inc., and its subsidiaries, collectively.

1. **Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.**

   None.

2. **Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.**

   None.

3. **Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.**

   None.

4. **Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.**

   None.

5. **Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.**

   Great Northern Transmission Line. As a condition of the 250-MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220-mile 500-kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

   In a 2016 order, the MPUC approved the route permit for the GNTL, and in 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. To date, most of the right-of-way has been cleared while foundation installation and transmission tower construction have commenced. The total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, of which Minnesota Power's portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as non-shareholder contributions to capital. Total project costs of $380.8 million have been incurred through December 31, 2018, of which $203.7 million has been recovered from a subsidiary of Manitoba Hydro.

   Manitoba Hydro must obtain regulatory and governmental approvals related to the MMTP, a new transmission line in Canada that will connect with the GNTL.

   Also see *Note 11. Commitments, Guarantees and Contingencies – Transmission* and *Note 4. Regulatory Matters* in the Notes to Financial Statements beginning on Page 123 of this FERC Form 1.

6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.

See *Note 10. Short-Term and Long-Term Debt* and *Note 12. Common Stock and Earnings Per Share* in the Notes to Financial Statements beginning on Page 123 of this FERC Form 1.

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.

None.

8. State the estimated annual effect and nature of any important wage scale changes during the year.

Minnesota Power has an aggregate of 1,038 employees of which 415 are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The labor agreements with IBEW Local 31 will expire on April 30, 2020.

Minnesota Power union employees received a 3.15 percent increase, effective February 2, 2019, which is an estimated increase of $1.0 million annualized. An average wage increase of 2.0 percent was granted to non-union employees effective March 2, 2019. The estimated annual effect of the non-union employees increase is expected to be approximately $1.1 million annualized.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.

See Note 11. Commitments, Guarantees and Contingencies – Other Matters – Legal Proceedings in the Notes to Financial Statements beginning on Page 123 of this FERC Form 1.

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.

None.

11. (Reserved.)

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and secondary wood products, pipeline and other industries.

Taconite and Iron Concentrate. Minnesota Power's taconite customers are capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than ten percent of Minnesota taconite production has been exported outside of North America. Minnesota Power also has provided electric service to three iron concentrate facilities capable of producing up to approximately 4 million tons of iron concentrate per year. Iron concentrate is used in the production of taconite pellets. These facilities have been idled since at least 2016. On July 17, 2018, ERP Iron Ore announced it would no longer seek to restart its operations. (See ERP Iron Ore / Magnetation.)

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 78 percent of capacity in 2018 (74 percent in 2017 and 71 percent in 2016). The World Steel Association, an association of over 160 steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2019 will increase by approximately one percent compared to 2018.

Minnesota Power's taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in Minnesota Power's taconite customers' production would impact our annual earnings per share by approximately $0.04, net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Minnesota Power proactively sells power in the wholesale power markets that is temporarily not required by industrial customers to optimize the value of its generating facilities. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead Minnesota Power to file a general rate case to recover lost revenue.

USS Corporation. In the first quarter of 2017, USS Corporation restarted its Minnesota Ore Operations Keetac plant in Keewatin, Minnesota, which had been idled since 2015. USS Corporation has the capability to produce approximately 5 million tons at its Keetac Plant.

United Taconite. In May 2017, Cliffs announced that production of a fully fluxed taconite pellet has started at its United Taconite facility. The product replaced a flux pellet previously made at Cliffs' indefinitely idled Empire operation in Michigan. United Taconite has the capability to produce approximately 5 million tons of taconite annually.

Northshore Mining. Cliffs has announced that it is investing further in its Minnesota ore operations, specifically it plans to invest approximately $90 million through 2020 to expand capacity for producing direct reduced-grade pellets at Northshore Mining. The additional direct reduced-grade pellets could be sold commercially or used to supply Cliff's planned hot briquetted iron production plant in Toledo, Ohio. Minnesota Power has a PSA through 2031 with Silver Bay Power, which provides the majority of the electric service requirements for Northshore Mining. (See Silver Bay Power.)

Silver Bay Power. In 2016, Minnesota Power and Silver Bay Power entered into a PSA through 2031. Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power, which has been served predominately through self-generation by Silver Bay Power. Through 2019, Minnesota Power will supply Silver Bay Power with at least 50 MW of energy and Silver Bay Power has the option to purchase additional energy from Minnesota Power as it transitions away from self-generation. By December 31, 2019, Silver Bay Power is expected to cease self-generation and Minnesota Power is expected to supply the energy requirements for Silver Bay Power.

ERP Iron Ore / Magnetation. In January 2017, ERP Iron Ore purchased substantially all of Magnetation's assets pursuant to an asset purchase agreement approved by the U. S. Bankruptcy Court for the District of Minnesota. These facilities have been idled since at least 2016. On July 17, 2018, ERP Iron Ore filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Minnesota and announced that it would no longer seek to restart its operations. Minnesota Power has reserved for all receivables due from ERP Iron Ore.

Paper, Pulp and Secondary Wood Products. The four major paper and pulp mills we serve reported operating at lower levels in 2018 compared to 2017 resulting from the closure of the smaller of UPM Blandin's two paper machines in the fourth quarter of 2017. (See UPM Blandin.) We expect operating levels in 2019 to be similar to 2018.

UPM Blandin. In October 2017, UPM-Kymmene Corporation announced that in light of the global market for graphic papers, and to sustain its competitiveness and leading position in the market, it planned to permanently close the smaller of UPM Blandin's two paper machines located in Grand Rapids, Minnesota; the closure was completed in the fourth quarter of 2017. Paper production related to the other paper machine is planned to continue at UPM Blandin. Minnesota Power provides electric and steam service to UPM Blandin. In October 2018, Minnesota Power amended and extended its electric service agreement with UPM Blandin through 2029, subject to MPUC approval.

Verso Corporation. In the third quarter of 2018, Minnesota Power amended and extended its electric service agreement with Verso Corporation through 2024, which was approved by the MPUC at a hearing on December 20, 2018.

Pipeline and Other Industries.

Husky Energy. On April 26, 2018, a fire at Husky Energy's refinery in Superior, Wisconsin disrupted operations at the facility. Under normal operating conditions, SWL&P provides approximately 14 MW of average monthly demand to Husky Energy in addition to water service. The facility remains at minimal operations, and the refinery is not expected to resume normal operations until 2020.

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource-based projects that represent long-term growth potential and load diversity for Minnesota Power. We cannot predict the outcome of these projects.

Nashwauk Public Utilities Commission. Mesabi Metallics is a retail customer of the Nashwauk Public Utilities Commission, and Minnesota Power has a wholesale electric contract with the Nashwauk Public Utilities Commission for electric service through at least December 2032. Mesabi Metallics filed for bankruptcy protection in 2016 under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware. In June 2017, the bankruptcy court approved a settlement plan for a consortium led by Chippewa Capital Partners LLC to take control of the project, subject to certain stipulations. In December 2017, Mesabi Metallics emerged from bankruptcy under the ownership of Chippewa Capital Partners LLC.

PolyMet. PolyMet is planning to start a new copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. In 2015, PolyMet announced the completion of the final EIS by state and federal agencies, which was subsequently published in the Federal Register and Minnesota Environmental Quality Board Monitor. The Minnesota Department of Natural Resources (DNR) issued its Record of Decision in 2016, finding the final EIS adequate. The final EIS also requires Records of Decision by the federal agencies, which are expected in 2019, before final action can be taken on the required federal permits to construct and operate the mining operation.

In 2016, PolyMet submitted applications for water-related permits with the DNR and MPCA, an air quality permit with the MPCA, and a state permit to mine application with the DNR detailing its operational plans for the mine. On November 1, 2018, the DNR issued PolyMet's permit to mine and certain water-related permits. On December 20, 2018, the MPCA issued PolyMet's final state water and air quality permits. PolyMet's remaining federal permit is under review by the U.S. Army Corps of Engineers. On June 28, 2018, the U.S. Forest Service and PolyMet closed on a land exchange, which resulted in PolyMet obtaining surface rights to land needed to develop its mining operation. Minnesota Power could supply between 45 MW and 50 MW of load under a 10-year power supply contract with PolyMet that would begin upon start-up of operations.

Renewable Energy. Minnesota Power's 2015 IRP includes an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. Minnesota Power continues to execute its renewable energy strategy through renewable projects that will ensure it meets the identified state mandate at the lowest cost for customers. Minnesota Power has exceeded the interim milestone requirements to date and expects between 25 percent and 30 percent of its applicable retail and municipal energy sales will be supplied by renewable energy sources in 2019.

Minnesota Solar Energy Standard. Minnesota Power's solar energy supply consists of Camp Ripley, a 10 MW solar energy facility at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, and a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. In an order dated October 2, 2018, the MPUC approved a PPA for the output of the 10 MW Blanchard solar energy facility to be located in central Minnesota. Minnesota Power expects that Camp Ripley, the community solar garden arrays, the PPA for the output of the 10 MW Blanchard solar energy facility, and an increase in solar rebates will allow Minnesota Power to meet both parts of the solar mandate.

Minnesota Power has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. Currently, there is no approved customer billing rate for solar costs.

Wind Energy. Minnesota Power's wind energy facilities consist of Bison (497 MW) located in North Dakota and Taconite Ridge (25 MW) located in northeastern Minnesota. Minnesota Power also has two long-term wind energy PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) located in North Dakota.

Minnesota Power uses the 465-mile, 250-kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota, to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to its system over this transmission line from Square Butte's lignite coal-fired generating unit. The DC transmission line capacity can be increased if renewable energy or transmission needs justify investments to upgrade the line.

Minnesota Power has an approved cost recovery rider for certain renewable investments and expenditures. The cost recovery rider allows Minnesota Power to charge retail customers on a current basis for the costs of certain renewable investments plus a return on the capital invested. Updated customer billing rates for the renewable cost recovery rider were provisionally approved by the MPUC in an order dated November 19, 2018.

Nobles 2 PPA. In the third quarter of 2018, Minnesota Power and Nobles 2 signed an amended long-term PPA that provides for Minnesota Power to purchase the energy and associated capacity from a 250 MW wind energy facility in southwestern Minnesota for a 20-year period beginning in 2020. The agreement provides for the purchase of output from the facility at fixed energy prices. There are no fixed capacity charges, and Minnesota Power will only pay for energy as it is delivered. This agreement is subject to construction of the wind energy facility. (See Note 5. Equity Investments in the Notes to Financial Statements beginning on Page 123 of this FERC Form 1.)

Manitoba Hydro. Minnesota Power has five long-term PPAs with Manitoba Hydro. The first PPA expires in May 2020. Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index. Under the second PPA, Minnesota Power is purchasing surplus energy through April 2022. This energy-only agreement primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term.

The third PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro for 15 years beginning in 2020. The PPA is subject to construction of the GNTL and MMTP. The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

The fourth PPA provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro for 20 years beginning in 2020. The pricing under this PPA is based on forward market prices. The PPA is subject to the construction of the GNTL and MMTP.

The fifth PPA provides for Minnesota Power to purchase 50 MW of capacity from Manitoba Hydro at fixed prices. The PPA began in June 2017 and expires in May 2020.

Also see *Note 4. Regulatory Matters, Note 11. Commitments, Guarantees and Contingencies – Power Purchase Agreements, Note 11. Commitments, Guarantees and Contingencies – Transmission, and Note 11. Commitments, Guarantees and Contingencies – Environmental Matters* in the Notes to Financial Statements beginning on Page 123 of this FERC Form 1.

13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.

Susan K. Nestegard was elected to the ALLETE, Inc. Board of Directors on January 16, 2018.

ALLETE, Inc. has been rescaling the operations and overall cost structure of its regulated business, Minnesota Power. As part of that ongoing focus, on November 26, 2018, the Company eliminated the position that consisted of the combined roles of Senior Vice President ALLETE – Chief Strategy Officer Regulated Operations and President Superior Water, Light and Power Company, which was held by Deborah A. Amberg.

14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

Ratio is not less than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,373,086,001	4,416,116,418
3	Construction Work in Progress (107)	200-201	245,619,192	119,754,417
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,618,705,193	4,535,870,835
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,519,751,227	1,489,396,244
6	Net Utility Plant (Enter Total of line 4 less 5)		3,098,953,966	3,046,474,591
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,098,953,966	3,046,474,591
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		17,896,652	17,711,559
19	(Less) Accum. Prov. for Depr. and Amort. (122)		5,297,195	5,517,530
20	Investments in Associated Companies (123)		-22,668,429	-22,668,429
21	Investment in Subsidiary Companies (123.1)	224-225	861,287,451	794,713,721
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		7,181,929	8,742,333
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		858,400,408	792,981,654
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		5,980,559	10,564,546
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	27,764
38	Temporary Cash Investments (136)		39,775,009	54,140,903
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		67,067,827	60,750,361
41	Other Accounts Receivable (143)		2,075,909	2,246,567
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		250,000	250,000
43	Notes Receivable from Associated Companies (145)		103,937,500	120,575,000
44	Accounts Receivable from Assoc. Companies (146)		33,869,209	22,452,089
45	Fuel Stock (151)	227	25,994,422	34,846,282
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	26,946,830	27,964,187
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		10,820,649	10,075,381
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		38,185	7,592
61	Accrued Utility Revenues (173)		17,971,929	18,758,564
62	Miscellaneous Current and Accrued Assets (174)		7,216,882	11,525,510
63	Derivative Instrument Assets (175)		333,169	582,608
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		341,778,079	374,267,354
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		7,400,556	7,762,831
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	369,077,377	359,159,144
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		583	0
77	Temporary Facilities (185)		78,431	66,739
78	Miscellaneous Deferred Debits (186)	233	52,379,265	58,688,377
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		1,322,162	1,558,142
82	Accumulated Deferred Income Taxes (190)	234	578,811,873	601,061,511
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,009,070,247	1,028,296,744
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,308,202,700	5,242,020,343

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	1,373,027,275	1,345,909,924
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	55,390,856	55,353,758
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	516,233,554	493,059,944
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	238,467,543	196,471,732
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-26,658,449	-21,528,736
16	Total Proprietary Capital (lines 2 through 15)		2,156,460,779	2,069,266,622
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,343,300,000	1,363,300,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	13,090,677	14,045,621
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,488	2,538
24	Total Long-Term Debt (lines 18 through 23)		1,356,389,189	1,377,343,083
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,141,585	2,629,467
29	Accumulated Provision for Pensions and Benefits (228.3)		172,780,943	186,563,346
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		50,007,722	23,663,357
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		96,900,505	77,390,597
35	Total Other Noncurrent Liabilities (lines 26 through 34)		321,830,755	290,246,767
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		121,855,432	119,963,634
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		10,168,619	22,393,428
41	Customer Deposits (235)		131	55,715
42	Taxes Accrued (236)	262-263	41,264,880	36,664,784
43	Interest Accrued (237)		17,717,649	17,454,818
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,589,680	1,544,013
48	Miscellaneous Current and Accrued Liabilities (242)		30,073,755	25,549,533
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		222,670,146	223,625,925
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,261,873	2,256,928
57	Accumulated Deferred Investment Tax Credits (255)	266-267	31,996,773	32,607,536
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	26,630,610	28,246,065
60	Other Regulatory Liabilities (254)	278	481,511,648	475,527,687
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	85,031,557	87,645,512
63	Accum. Deferred Income Taxes-Other Property (282)		536,829,457	564,538,982
64	Accum. Deferred Income Taxes-Other (283)		86,589,913	90,715,236
65	Total Deferred Credits (lines 56 through 64)		1,250,851,831	1,281,537,946
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,308,202,700	5,242,020,343

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,021,400,291	1,026,492,100		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	599,579,033	595,438,132		
5	Maintenance Expenses (402)	320-323	70,041,761	74,598,903		
6	Depreciation Expense (403)	336-337	147,561,954	123,001,345		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,229,411	994,706		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,887,383	4,180,091		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	29,496	29,496		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		74,712	74,712		
13	(Less) Regulatory Credits (407.4)		2,146,423	1,643,104		
14	Taxes Other Than Income Taxes (408.1)	262-263	49,200,786	48,002,161		
15	Income Taxes - Federal (409.1)	262-263	-1,254	-380		
16	- Other (409.1)	262-263	9,985	-18,429		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	105,405,377	165,580,569		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	124,621,807	148,741,898		
19	Investment Tax Credit Adj. - Net (411.4)	266	-603,818	-493,052		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		2,808	1,904		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		715,134	826,462		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		851,358,922	861,827,810		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		170,041,369	164,664,290		

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,021,400,291	1,026,492,100					2
						3
599,579,033	595,438,132					4
70,041,761	74,598,903					5
147,561,954	123,001,345					6
1,229,411	994,706					7
4,887,383	4,180,091					8
29,496	29,496					9
						10
						11
74,712	74,712					12
2,146,423	1,643,104					13
49,200,786	48,002,161					14
-1,254	-380					15
9,985	-18,429					16
105,405,377	165,580,569					17
124,621,807	148,741,898					18
-603,818	-493,052					19
						20
						21
2,808	1,904					22
						23
715,134	826,462					24
851,358,922	861,827,810					25
170,041,369	164,664,290					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		170,041,369	164,664,290		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		25,451,084	20,613,830		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		24,848,639	20,481,826		
33	Revenues From Nonutility Operations (417)		13,060,392	14,976,424		
34	(Less) Expenses of Nonutility Operations (417.1)		13,547,752	16,779,209		
35	Nonoperating Rental Income (418)		2,218,028	2,120,774		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	58,808,715	71,050,079		
37	Interest and Dividend Income (419)		5,130,491	6,357,960		
38	Allowance for Other Funds Used During Construction (419.1)		1,076,956	1,147,439		
39	Miscellaneous Nonoperating Income (421)		-95,301	-139,122		
40	Gain on Disposition of Property (421.1)		949,538			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		68,203,512	78,866,349		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		20,792	538,313		
44	Miscellaneous Amortization (425)		217,475	197,424		
45	Donations (426.1)		268,044	1,430,200		
46	Life Insurance (426.2)		-729,935	-1,447,351		
47	Penalties (426.3)		939	6,289		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		459,449	256,062		
49	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		236,764	980,937		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,419,182	1,346,618		
53	Income Taxes-Federal (409.2)	262-263				
54	Income Taxes-Other (409.2)	262-263	-75	-150		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	9,821,341	18,175,733		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	10,396,463	10,442,502		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		843,985	9,079,699		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		67,122,763	68,805,713		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		58,930,907	58,176,153		
63	Amort. of Debt Disc. and Expense (428)		966,848	1,007,714		
64	Amortization of Loss on Reaquired Debt (428.1)		235,980	235,980		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		3,281,489	2,193,580		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		336,257	349,759		
70	Net Interest Charges (Total of lines 62 thru 69)		63,078,967	61,263,668		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		174,085,165	172,206,335		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		174,085,165	172,206,335		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		493,059,944	494,165,152
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Accounting Policy Adoption Adjustment		5,425,578	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		5,425,578	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		115,276,450	101,156,256
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	2017 Year-to-date Dividends			(108,661,464)
32	2018 Year-to-date Dividends		-115,028,418	
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-115,028,418	(108,661,464)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		17,500,000	6,400,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		516,233,554	493,059,944
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		516,233,554	493,059,944
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		196,471,732	131,821,653
50	Equity in Earnings for Year (Credit) (Account 418.1)		58,808,715	71,050,079
51	(Less) Dividends Received (Debit)			
52	Transfers from Account 216.1		-16,812,904	(6,400,000)
53	Balance-End of Year (Total lines 49 thru 52)		238,467,543	196,471,732

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	174,085,165	172,206,335
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	154,319,948	129,367,888
5	Amortization of		
6	Debt Issuance Costs	1,203,878	1,244,745
7	Stock Compensation Expense	2,702,770	2,538,974
8	Deferred Income Taxes (Net)	-19,791,553	24,571,902
9	Investment Tax Credit Adjustment (Net)	-603,818	-493,052
10	Net (Increase) Decrease in Receivables	-2,333,698	-8,585,355
11	Net (Increase) Decrease in Inventory	9,869,217	10,866,808
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	13,803,624	-2,733,394
14	Net (Increase) Decrease in Other Regulatory Assets	43,640,529	-75,026,811
15	Net Increase (Decrease) in Other Regulatory Liabilities	-59,092,473	89,819,844
16	(Less) Allowance for Other Funds Used During Construction	1,076,956	1,147,439
17	(Less) Undistributed Earnings from Subsidiary Companies	58,808,715	71,050,079
18	Other (provide details in footnote):	806,853	19,108,178
19	Accumulated Provision for Rate Refunds	16,347,540	23,663,357
20	Tax Reform Refunds	9,996,825	
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	285,069,136	314,351,901
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-180,210,919	-107,812,763
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-1,076,956	-1,147,439
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-179,133,963	-106,665,324
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Proceeds from Sale of Minnesota Power Land	1,407,270	531,282
39	Investments in and Advances to Assoc. and Subsidiary Companies	-25,265,015	-87,658,663
40	Contributions and Advances from Assoc. and Subsidiary Companies	9,903,315	6,400,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-146,361	-137,001
45	Proceeds from Sales of Investment Securities (a)	100,000	300,000

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	1,223,179	-631,313
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-191,911,575	-187,861,019
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	60,000,000	120,000,000
62	Preferred Stock		
63	Common Stock	24,451,678	91,153,367
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	84,451,678	211,153,367
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-80,954,944	-175,925,740
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-603,522	-565,384
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-115,028,418	-108,661,464
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-112,135,206	-73,999,221
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-18,977,645	52,491,661
87			
88	Cash and Cash Equivalents at Beginning of Period	64,733,213	12,241,552
89			
90	Cash and Cash Equivalents at End of period	45,755,568	64,733,213

Schedule Page: 120 Line No.: 18 Column: b

Net Increase (Decrease) in Other Current Assets

Retirement Savings and Stock Ownership Plan Compensation Expense	$3,091,910
Unbilled Revenue	786,635
Gain on Sale of Available-for-sale Securities	(21,842)
Rent Receivable	(30,593)
Deferred Fuel Adjustment Costs	(69,000)
Prepayments	(2,950,257)
	$806,853

Schedule Page: 120 Line No.: 18 Column: c

Net Increase (Decrease) in Other Current Assets

Deferred Fuel Adjustment Costs	$18,697,000
Retirement Savings and Stock Ownership Plan Compensation Expense	3,409,538
Rent Receivable	118,377
Prepayments	77,833
Gain on Sale of Available-for-sale Securities	(35,714)
Unbilled Revenue	(3,158,856)
	$19,108,178

Schedule Page: 120 Line No.: 53 Column: b

Net (Increase) Decrease in Other Investments and Non-Regulatory Assets

Pension and Other Postretirement Benefit Investment Accounts (Grantor and Rabbi Trusts)	$1,628,607
Other Non-Utility Property	(405,428)
	$1,223,179

Schedule Page: 120 Line No.: 53 Column: c

Net (Increase) Decrease in Other Investments and Non-Regulatory Assets

Other Non-Utility Property	$59,197
Pension and Other Postretirement Benefit Investment Accounts (Grantor and Rabbi Trusts)	(690,510)
	($631,313)

Schedule Page: 120 Line No.: 76 Column: b

Other

Debt Issuance Costs	($603,522)

Schedule Page: 120 Line No.: 76 Column: c

Other

Debt Issuance Costs	($565,384)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	(978,859)	(26,418,090)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(20,993)	691,464		
3	Preceding Quarter/Year to Date Changes in Fair Value	909,873	4,287,869		
4	Total (lines 2 and 3)	888,880	4,979,333		
5	Balance of Account 219 at End of Preceding Quarter/Year	(89,979)	(21,438,757)		
6	Balance of Account 219 at Beginning of Current Year	(89,979)	(21,438,757)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		908,698		
8	Current Quarter/Year to Date Changes in Fair Value	89,979	(6,128,390)		
9	Total (lines 7 and 8)	89,979	(5,219,692)		
10	Balance of Account 219 at End of Current Quarter/Year		(26,658,449)		

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(27,396,949)	[redacted]	
2			670,471	[redacted]	
3			5,197,742	[redacted]	
4			5,868,213	172,206,335	178,074,548
5			(21,528,736)	[redacted]	
6			(21,528,736)	[redacted]	
7			908,698	[redacted]	
8			(6,038,411)	[redacted]	
9			(5,129,713)	174,085,165	168,955,452
10			(26,658,449)	[redacted]	

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Abbreviations and acronyms used in the text are defined beginning on page 123.74 of this FERC Form 1.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Preparation. References in this report to “we,” “us,” and “our” are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with GAAP. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. Actual results could differ from those estimates.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

On February 8, 2019, the Company entered into a stock purchase agreement providing for the sale of U.S. Water Services to a subsidiary of Kurita Water Industries Ltd. for a cash purchase price of $270 million, subject to adjustment at closing, such as for changes in working capital. The transaction is expected to close by the end of the first quarter of 2019 upon receipt of regulatory approval. The Company expects to recognize a gain on the sale of U.S. Water Services estimated at approximately $10 million after-tax.

Principles of Consolidation. Our Consolidated Financial Statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. We present three reportable segments: Regulated Operations, ALLETE Clean Energy and U.S. Water Services. Our segments were determined in accordance with the guidance on segment reporting. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated utility electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 545 MW of nameplate capacity wind energy generation that is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage, and improve efficiency.

Corporate and Other is comprised of BNI Energy, our investment in Nobles 2, ALLETE Properties, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 4,000 acres of land in Minnesota, and earnings on cash and investments.

BNI Energy mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2018, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under long-term contracts. (See Note 11. Commitments, Guarantees and Contingencies.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

ALLETE Properties represents our legacy Florida real estate investment. Our strategy incorporates the possibility of a bulk sale of the entire ALLETE Properties portfolio. Proceeds from a bulk sale would be strategically deployed to support growth at our Regulated Operations and ALLETE Clean Energy. ALLETE Properties continues to pursue sales of individual parcels over time and will continue to maintain key entitlements and infrastructure. (See Note 8. Investments.)

Cash, Cash Equivalents and Restricted Cash. We consider all investments purchased with original maturities of three months or less to be cash equivalents. Restricted cash amounts included in Prepayments and Other on the Consolidated Balance Sheet include collateral deposits required under an ALLETE Clean Energy loan agreement and U.S. Water Services' standby letters of credit. The restricted cash amounts included in Other Non-Current Assets represent collateral deposits required under an ALLETE Clean Energy loan agreement and PSAs, and deposits from a SWL&P customer in aid of future capital expenditures. The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheet that aggregate to the amount presented in the Consolidated Statement of Cash Flows. During the first quarter of 2018, the Company updated the presentation of its Consolidated Statement of Cash Flows to include restricted cash with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. (See *Recently Adopted Pronouncements - Statement of Cash Flows: Restricted Cash*.)

Cash, Cash Equivalents and Restricted Cash	**December 31, 2018**	**December 31, 2017**	**December 31, 2016**
Millions			
Cash and Cash Equivalents	$69.1	$98.9	$27.5
Restricted Cash included in Prepayments and Other	1.3	2.6	2.2
Restricted Cash included in Other Non-Current Assets	8.6	8.6	8.6
Cash, Cash Equivalents and Restricted Cash on the Consolidated Statement of Cash Flows	$79.0	$110.1	$38.3

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Supplemental Statement of Cash Flow Information.

Consolidated Statement of Cash Flows

Year Ended December 31	2018	2017	2016
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$66.0	$64.5	$68.2
Remeasurement of Deferred Income Taxes Resulting from the TCJA			
Increase in Regulatory Assets	—	$80.9	—
Decrease in Investment in ATC	—	$(27.9)	—
Decrease in Deferred Income Taxes	—	$(353.6)	—
Increase in Regulatory Liabilities	—	$393.6	—
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(0.1)	$67.2	$(22.0)
Reclassification of Property, Plant and Equipment to Inventory *(a)*	$46.3	—	—
Capitalized Asset Retirement Costs	$14.2	$(15.6)	$3.7
Camp Ripley Solar Financing	—	—	$15.0
AFUDC–Equity	$1.2	$1.2	$2.1
ALLETE Common Stock Contributed to Pension Plans	—	$13.5	—
ALLETE Common Stock Received for Land Inventory	—	—	$8.0
Long-Term Finance Receivable for Land Inventory	—	—	$12.0

(a) On February 28, 2018, Montana-Dakota Utilities exercised its option to purchase the Thunder Spirit II wind energy facility upon completion, resulting in a $46.3 million reclassification from Property, Plant and Equipment – Net to Inventories – Net for project costs incurred in the prior year. On the Consolidated Statement of Cash Flows, the sale of the wind energy facility in the fourth quarter of 2018 resulted in Operating Activities – Inventories increasing by $46.3 million in 2018 due to the project costs incurred in the prior year.

Accounts Receivable. Accounts receivable are reported on the Consolidated Balance Sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific situations and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable

As of December 31	2018	2017
Millions		
Trade Accounts Receivable		
Billed	$121.7	$112.6
Unbilled	24.4	24.6
Less: Allowance for Doubtful Accounts	1.7	2.1
Total Accounts Receivable	$144.4	$135.1

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Concentration of Credit Risk. We are subject to concentration of credit risk primarily as a result of accounts receivable. Minnesota Power sells electricity to eight Large Power Customers. Receivables from these customers totaled $11.7 million as of December 31, 2018 ($13.8 million as of December 31, 2017). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates, which allows us to closely manage collection of amounts due. One of these customers accounted for 10 percent of consolidated operating revenue in 2018 (10 percent in 2017 and 8 percent in 2016).

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals.

Available-for-Sale Securities. Available-for-sale debt and equity securities are recorded at fair value. Unrealized gains and losses on available-for-sale debt securities are included in accumulated other comprehensive income (loss), net of tax. Unrealized gains and losses on available-for-sale equity securities are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. (See Note 8. Investments.)

Inventories – Net. Inventories are stated at the lower of cost or net realizable value. Inventories in our Regulated Operations segment are carried at an average cost or first-in, first-out basis. Inventories in our U.S. Water Services and ALLETE Clean Energy segments, and Corporate and Other businesses are carried at an average cost, first-in, first-out or specific identification basis.

Inventories – Net

As of December 31	**2018**	**2017**
Millions		
Fuel *(a)*	$26.0	$34.8
Materials and Supplies	44.2	46.5
Raw Materials	2.8	2.8
Work in Progress	6.1	4.2
Finished Goods	8.4	8.3
Reserve for Obsolescence	(0.8)	(0.7)
Total Inventories – Net	$86.7	$95.9

(a) Fuel consists primarily of coal inventory at Minnesota Power.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the Consolidated Balance Sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on property, plant and equipment in our U.S. Water Services segment and Corporate and Other operations are recognized when they are retired or otherwise disposed. When property, plant and equipment in our Regulated Operations and ALLETE Clean Energy segments are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for component depreciation except for certain circumstances where the retirement is unforeseen or unexpected. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. Upon MPUC approval of cost recovery, the recognition of AFUDC ceases. (See Note 2. Property, Plant and Equipment.)

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. In 2015, Minnesota Power retired Taconite Harbor Unit 3 and converted Laskin to operate on natural gas. Minnesota Power's 2015 IRP contained steps in Minnesota Power's *EnergyForward* plan including the economic idling of Taconite Harbor Units 1 and 2 in 2016, and the ceasing of coal-fired operations at Taconite Harbor in 2020. (See Note 4. Regulatory Matters.) The MPUC order for the 2015 IRP also directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022. Minnesota Power retired Boswell Units 1 and 2 in the fourth quarter of 2018. As part of the 2016 general retail rate case, the MPUC allowed recovery of the remaining book value of Boswell Units 1 and 2 through 2022. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3, the ceasing of coal-fired operations at Taconite Harbor Units 1 and 2 or the conversion of Laskin to operate on natural gas. In addition, we expect to be able to continue depreciating these assets for at least their established remaining useful lives; however, we are unable to predict the impact of regulatory outcomes resulting in changes to their established remaining useful lives.

Impairment of Long-Lived Assets. We review our long-lived assets, which include the legacy real estate assets of ALLETE Properties, for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to estimated fair value.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our long-lived assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations.

In 2018, 2017, and 2016, our qualitative assessments indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded in 2018, 2017, or 2016.

Derivatives. ALLETE is exposed to certain risks relating to its business operations that can be managed through the use of derivative instruments. ALLETE may enter into derivative instruments to manage those risks including interest rate risk related to certain variable-rate borrowings.

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 16. Employee Stock and Incentive Plans.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Goodwill and Intangible Assets.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with GAAP, goodwill is not amortized. Goodwill is assessed annually in the fourth quarter for impairment and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level.

As part of the 2016 annual impairment analysis, the Company recognized a non-cash impairment charge of $3.3 million for ALLETE Clean Energy's goodwill primarily related to the acquisition of Storm Lake II in 2014. The charge, which is presented within Operating Expenses – Other in the Consolidated Statement of Income, eliminated all recognized goodwill for the ALLETE Clean Energy reporting unit.

As of the date of our annual goodwill impairment testing in 2018, the U.S. Water Services reporting unit had positive equity and the Company elected to bypass the qualitative assessment of goodwill for impairment, proceeding directly to the two-step impairment test. In performing Step 1 of the impairment test, we compared the fair value of the reporting unit to its carrying value including goodwill. If the carrying value including goodwill were to exceed the fair value of a reporting unit, Step 2 of the impairment test would be performed. Step 2 of the impairment test requires the carrying value of goodwill to be reduced to its fair value, if lower, as of the test date.

U.S. Water Services. For Step 1 of the impairment test, we estimated the reporting unit's fair value using standard valuation techniques, including techniques which use estimates of projected future results and cash flows to be generated by the reporting unit. Such techniques generally include a terminal value that utilizes a growth rate on debt-free cash flows. These cash flow valuations involve a number of estimates that require broad assumptions and significant judgment by management regarding future performance. Our annual impairment test in 2018 indicated that the estimated fair value of U.S. Water Services exceeded its carrying value, and therefore no impairment existed (none in 2017 or in 2016). The fair value of the reporting unit was determined using a discounted cash flow model, using significant assumptions which included a discount rate of 12.0 percent, cash flow forecasts through 2023, annual revenue growth rates ranging from 6.0 percent to 10.0 percent, and a terminal growth rate of 3.5 percent. Forecasted annual revenue growth assumes an increase in market share and growth in the industry. (See *Subsequent Events*.)

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements, land easements, trademarks and trade names. Intangible assets with definite lives consist of customer relationships, which are amortized using an attrition model, and patents, non-compete agreements, land easements and certain trade names, which are amortized on a straight-line basis with estimated remaining useful lives ranging from approximately 4 years to approximately 19 years. We review definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and certain trade names, which are tested for impairment annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset's carrying amount over its fair value. Fair value is generally determined using a discounted cash flow analysis. Our annual impairment test in 2018 indicated that the estimated fair value of trademarks and trade names exceeded the asset carrying values. As a result, no impairment existed in 2018 (none in 2017 or in 2016).

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Non-Current Assets

As of December 31	**2018**	**2017**
Millions		
Contract Assets *(a)*	$30.7	$31.6
Finance Receivable *(b)*	10.4	11.0
Other	62.2	65.1
Total Other Non-Current Assets	$103.3	$107.7

(a) Contract Assets include payments made to customers as an incentive to execute or extend service agreements. The contract payments are being amortized over the term of the respective agreements as a reduction to revenue.

(b) Finance Receivable reflects the remaining balance due from the ALLETE Properties sale of its Ormond Crossings project and Lake Swamp wetland mitigation bank.

Other Current Liabilities

As of December 31	**2018**	**2017**
Millions		
Provision for Interim Rate Refund	$40.0	—
PSAs	12.6	$24.5
Contract Liabilities *(a)*	7.6	8.7
Provision for Tax Reform Refund	10.7	—
Contingent Consideration *(b)*	3.8	—
Other	53.8	50.0
Total Other Current Liabilities	$128.5	$83.2

(a) Contract Liabilities include deposits received as a result of entering into contracts with our customers prior to completing our performance obligations.

(b) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 9. Fair Value.)

Other Non-Current Liabilities

As of December 31	**2018**	**2017**
Millions		
Asset Retirement Obligation	$138.6	$122.7
PSAs	76.9	89.5
Contingent Consideration *(a)*	—	5.4
Other	47.1	49.5
Total Other Non-Current Liabilities	$262.6	$267.1

(a) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 9. Fair Value.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Environmental Liabilities. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers. (See Note 11. Commitments, Guarantees and Contingencies.)

Revenue.

Contracts with Customers – Utility includes sales from our regulated operations for generation, transmission and distribution of electric service, and distribution of water and gas services to our customers. Also included is an immaterial amount of regulated steam generation that is used by customers in the production of paper and pulp.

Contracts with Customers – Non-utility includes sales of goods and services to customers from ALLETE Clean Energy, U.S. Water Services and our Corporate and Other businesses.

Other – Non-utility is the non-cash adjustments to revenue recognized by ALLETE Clean Energy for the amortization of differences between contract prices and estimated market prices for PSAs that were assumed during the acquisition of various wind energy facilities.

Revenue Recognition

Revenue is recognized upon transfer of control of promised goods or services to our customers in an amount that reflects the consideration we expect to receive in exchange for those products or services. Revenue is recognized net of allowance for returns and any taxes collected from customers, which are subsequently remitted to the appropriate governmental authorities. We account for shipping and handling activities that occur after the customer obtains control of goods as a cost rather than an additional performance obligation thereby recognizing revenue at time of shipment and accruing shipping and handling costs when control transfers to our customers. We have a right to consideration from our customers in an amount that corresponds directly with the value to the customer for our performance completed to date; therefore, we may recognize revenue in the amount to which we have a right to invoice.

Nature of Revenue Streams

Utility

Residential and Commercial includes sales for electric, gas or water service to customers, who have implied contracts with the utility, under rates governed by the MPUC, PSCW or FERC. Customers are billed on a monthly cycle basis and revenue is recognized for electric, gas or water service delivered during the billing period. Revenue is accrued for service provided but not yet billed at period end. Performance obligations with these customers are satisfied at time of delivery to customer meters and simultaneously consumed.

Municipal includes sales to 16 non-affiliated municipal customers in Minnesota under long-term wholesale electric contracts. All wholesale electric contracts include a termination clause requiring a three-year notice to terminate. These contracts have termination dates ranging from 2019 through at least 2032, with a majority of contracts effective through at least 2024. Performance obligations with these customers are satisfied at the time energy is delivered to an agreed upon municipal substation or meter.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Revenue (Continued)

Industrial includes sales recognized from contracts with customers in the taconite mining, iron concentrate, paper, pulp and secondary wood products, pipeline and other industries. Industrial sales accounted for approximately 50 percent of total regulated utility kWh sales for the year ended December 31, 2018. Within industrial revenue, Minnesota Power has eight Large Power Customer contracts, each serving requirements of 10 MW or more of customer load. These contracts automatically renew past the contract term unless a four-year advanced written notice is given. Large Power Customer contracts have earliest termination dates ranging from 2022 through 2028. We satisfy our performance obligations for these customers at the time energy is delivered to an agreed upon customer substation. Revenue is accrued for energy provided but not yet billed at period end. Based on current contracts with industrial customers, we expect to recognize minimum revenue for the fixed contract components of approximately $75 million in 2019, $55 million per annum in 2020 through 2022, $25 million in 2023, and $75 million in total thereafter, which reflects the termination notice period in these contracts. When determining minimum revenue, we assume that customer contracts will continue under the contract renewal provision; however, if long-term contracts are renegotiated and subsequently approved by the MPUC or there are changes within our industrial customer class, these amounts may be impacted. Contracts with customers that contain variable pricing or quantity components are excluded from the expected minimum revenue amounts.

Other Power Suppliers includes the sale of energy under long-term PSAs with two customers as well as MISO market and liquidation sales. Expiration dates of these PSAs range from 2020 through 2028. Performance obligations with these customers are satisfied at the time energy is delivered to an agreed upon delivery point defined in the contract (generally the MISO pricing node). Based on current contracts with two customers, we expect to recognize minimum revenue for fixed contract components of approximately $10 million in 2019. Other power supplier contracts that extend beyond 2020 contain variable pricing components that prevent us from estimating future minimum revenue, and therefore are not included.

Other Revenue includes all remaining individually immaterial revenue streams for Minnesota Power and SWL&P, and is comprised of steam sales to paper and pulp mills, wheeling revenue and other sources. Revenue for steam sales to customers is recognized at the time steam is delivered and simultaneously consumed. Revenue is recognized at the time each performance obligation is satisfied.

Alternative Programs includes revenue that is driven by factors outside of our regulated entities' control or as a result of the achievement of certain objectives, such as CIP financial incentives. This revenue is accounted for in accordance with the accounting standards for alternative revenue programs which allow for the recognition of revenue under an alternative revenue program if the program is established by an order from the utility's regulatory commission, the order allows for automatic adjustment of future rates, the amount of revenue recognized is objectively determinable and probable of recovery, and the revenue will be collected within 24 months following the end of the annual period in which it is recognized. CIP financial incentives are recognized in the period in which the MPUC approves the filing, which is typically mid-year.

Non-utility

ALLETE Clean Energy

Long-term PSA revenue includes all sales recognized under long-term contracts for production, curtailment, capacity and associated renewable energy credits from ALLETE Clean Energy wind energy facilities. Expiration dates of these PSAs range from 2019 through 2032. Performance obligations for these contracts are satisfied at the time energy is delivered to an agreed upon point, or production is curtailed at the request of the customer, at specified prices. Revenue from the sale of renewable energy credits is recognized at the same time the related energy is delivered to the customer when sold to the same party.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Revenue (Continued)

Sale of Wind Energy Facility includes revenue recognized for the design, development, construction, and sale of a wind energy facility to a customer. Performance obligations for these types of agreements are satisfied at the time the completed project is transferred to the customer at the commercial operation date. Revenue from the sale of a wind energy facility is recognized at the time of asset transfer.

Other is the non-cash adjustments to revenue recognized by ALLETE Clean Energy for the amortization of differences between contract prices and estimated market prices on assumed PSAs. As part of wind energy facility acquisitions, ALLETE Clean Energy assumed various PSAs that were above or below estimated market prices at the time of acquisition; the resulting differences between contract prices and estimated market prices are amortized to revenue over the remaining PSA term.

U.S. Water Services

Point-in-time revenue is recognized for purchases by customers for chemicals, consumable equipment (e.g., filters, pumps and valves) or related maintenance and repair services as the customer’s usage and needs change over time. These goods and services are purchased on an as-needed basis by customers and therefore revenue can be variable. Products are shipped to customers in accordance with the terms of each purchase order, and performance obligations are satisfied at the time of shipment of goods or when services are rendered to the customer.

Contract includes monthly revenue from contracts with customers to provide chemicals, consumable equipment and services to meet customer needs during the contract period. As agreed with the customer, a fixed amount is invoiced based on the goods and services to be provided under the contract. The duration of these contracts generally range in length from three months to five years and automatically renew. A 30-day notice is required to terminate such contracts without penalty. Performance obligations are satisfied during the period as goods and service are delivered in accordance with the terms of the contract.

Capital Project includes the sale of equipment and other components assembled to create a water treatment system for a customer. These projects are provided under contracts at an agreed upon price to meet a customer's specifications and typically take less than one year to complete. In general, progress payments are received throughout the project period and are recorded as contract liabilities until performance obligations are satisfied at the time the equipment and other components are delivered to the customer’s site.

Corporate and Other

Long-term Contract encompasses the sale and delivery of coal to customer generation facilities. Revenue is recognized on a monthly basis at the cost of production plus a specified profit per ton of coal delivered to the customer. Coal sales are secured under long-term coal supply agreements extending through 2037. Performance obligations are satisfied during the period as coal is delivered to customer generation facilities.

Other primarily includes revenue from BNI Energy unrelated to coal, the sale of real estate from ALLETE Properties, and non-rate base steam generation that is sold for use during production of paper and pulp. Performance obligations are satisfied when control transfers to the customer.

See Note 17. Business Segments for additional detail of disaggregated revenue by nature of revenue stream.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Payment Terms

Payment terms and conditions vary across our businesses. Aside from taconite-producing Large Power Customers, payment terms generally require payment to be made within 15 to 30 days from the end of the period that the service has been rendered or goods provided. In the case of its taconite-producing Large Power Customers, as permitted by the MPUC, Minnesota Power requires weekly payments for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's estimate of the customers' energy usage, forecasted energy prices and fuel adjustment clause estimates. Minnesota Power's taconite-producing Large Power Customers have generally predictable energy usage on a weekly basis and any differences that occur are trued-up the following month. Due to the timing difference of revenue recognition from the timing of invoicing and payment, the customer receives credit for the time value of money; however, we have determined that our contracts do not include a significant financing component as the period between when we transfer the service to the customer and when they pay for such service is minimal.

Assets Recognized From the Costs to Obtain a Contract with a Customer

We recognize as an asset the incremental costs of obtaining a contract with a customer if we expect the benefit of those costs to be longer than one year. We expense incremental costs when the asset that would have resulted from capitalizing these costs would have been amortized in one year or less. As of December 31, 2018, we have $30.7 million of assets recognized for costs incurred to obtain contracts with our customers ($31.6 million as of December 31, 2017). Management determined the amount of costs to be recognized as assets based on actual costs incurred and paid to obtain and fulfill these contracts to provide goods and services to our customers. Assets recognized to obtain contracts are amortized on a straight-line basis over the contract term as a non-cash reduction to revenue. We recognized $2.6 million and $2.7 million of non-cash amortization for the year ended December 31, 2018 and 2017, respectively.

Operating Expenses – Other

Year Ended December 31	**2018**	**2017**	**2016**
Millions			
Impairment of Goodwill *(a)*	—	—	$3.3
Change in Fair Value of Contingent Consideration *(b)*	$(2.0)	$(0.7)	(13.6)
Total Operating Expenses – Other	$(2.0)	$(0.7)	$(10.3)

(a) See Goodwill and Intangible Assets.
(b) See Note 9. Fair Value.

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using a method which approximates the effective interest method.

Income Taxes. ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns. We account for income taxes using the liability method in accordance with GAAP for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Income Taxes (Continued)

Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with GAAP for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is “more-likely-than-not” to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term “more-likely-than-not” means more than 50 percent likely. (See Note 13. Income Tax Expense.)

Tax Cuts and Jobs Act of 2017. On December 22, 2017, the TCJA was enacted. Under ASC 740, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted. On December 22, 2017, the SEC staff issued guidance in Staff Accounting Bulletin 118 (SAB 118) which provided for up to a one-year period in which to complete the required analysis and accounting for the TCJA. The one-year period is now complete and the final impact was immaterial.

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

Purchase Accounting. In accordance with authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the Consolidated Balance Sheet if it exceeds the estimated fair value and as a bargain purchase gain on the Consolidated Income Statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management’s judgment, and the utilization of independent valuation experts as well as the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. (See Note 6. Acquisitions.)

New Accounting Pronouncements.

Recently Adopted Pronouncements

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. In February 2018, the FASB issued an update allowing for a one-time reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA. With the enactment of the new federal tax rates in 2017, entities were required to adjust deferred income tax assets and liabilities to reflect the lower federal rate. The effect of this reduction impacted income from continuing operations in the period of enactment, even in instances where the related income tax effects of items were originally recognized in other comprehensive income. As such, companies were left with stranded tax effects in accumulated other comprehensive income that did not reflect the appropriate tax rate. This guidance is effective in the first quarter of 2019 with early adoption permitted. The Company elected to early adopt this guidance in the first quarter of 2018, which resulted in a reduction of $5.7 million to Accumulated Other Comprehensive Loss and a corresponding increase to Retained Earnings for the reclassification of the stranded income tax effects.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
New Accounting Pronouncements (Continued)

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. In March 2017, the FASB issued an accounting standard update to improve the presentation of net periodic pension and postretirement benefit costs. Under the guidance, an entity is required to present the service cost component of the net periodic benefit cost in the same income statement line as other employee compensation costs arising from services rendered during the period. The guidance also allows only the service cost component of the periodic cost to be eligible for capitalization on a prospective basis. The other components of net periodic expense must be presented separately from the line item that includes the service cost and must be excluded from the operating income subtotal. The Company adopted the guidance in the first quarter of 2018 and retrospectively adjusted the presentation of the service cost component and the other components of net periodic costs in the Consolidated Statement of Income. The retrospective adjustments for the years ended December 31, 2017, and 2016, were as follows: Operating and Maintenance increased $4.2 million and $6.8 million, respectively, and Cost of Sales – Non-utility decreased $0.3 million in each year, resulting in an increase of $3.9 million and $6.5 million, respectively, to Other Income (Expense) – Other. There was no impact to net income as a result of adoption.

Financial Instruments. In 2016, the FASB issued an accounting standard update which requires entities to measure equity investments at fair value and recognize any changes in fair value in net income unless the investments qualify for the practicability exception. The practicability exception will be available for equity investments that do not have readily determinable fair values. The update was adopted by the Company in the first quarter of 2018 which resulted in a cumulative-effect transition adjustment reducing Retained Earnings by $0.1 million, including the tax effect, for the previously unrealized loss on available-for-sale equity securities in Accumulated Other Comprehensive Loss as of December 31, 2017.

Classification of Certain Cash Receipts and Cash Payments. In 2016, the FASB issued an accounting standard update which addresses the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments of this update were adopted by the Company in the first quarter of 2018. The adoption of this standard update resulted in an increase to Cash from Operating Activities of $2.9 million and a decrease to Cash for Financing Activities of a corresponding amount for the year ending December 31, 2016, due to the reclassification of debt extinguishment costs incurred by ALLETE Clean Energy in 2016.

Statement of Cash Flows: Restricted Cash. In 2016, the FASB issued an accounting standard update related to the presentation of restricted cash in the Company's Consolidated Statement of Cash Flows. The update requires that the Consolidated Statement of Cash Flows explain the change during the period in cash, cash equivalents and restricted cash. Restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. This standard update was adopted by the Company in the first quarter of 2018 and was applied retrospectively to the periods presented in the Consolidated Statement of Cash Flows, which resulted in a net decrease for Cash for Financing Activities of $0.4 million and $0.7 million for the years ended December 31, 2017 and 2016, respectively, and a decrease in Cash for Investing Activities of $4.1 million for the year ended December 31, 2016. A reconciliation of Cash and Cash Equivalents presented on the Consolidated Balance Sheet to Cash, Cash Equivalents and Restricted Cash presented on the Consolidated Statement of Cash Flows can be found above under *Cash, Cash Equivalents and Restricted Cash*.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
New Accounting Pronouncements (Continued)

Revenue from Contracts with Customers. In 2014, the FASB issued amended revenue recognition guidance that clarifies the principles for recognizing revenue from contracts with customers by providing a single comprehensive model to determine the measurement of revenue and timing of recognition. The guidance requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled to in exchange for those goods or services. The guidance requires expanded disclosures relating to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. Additionally, qualitative and quantitative disclosures regarding customer contracts, significant judgments and changes in those judgments, and the assets recognized from the costs to obtain or fulfill a contract are required. The Company adopted this accounting guidance in the first quarter of 2018 and elected to apply the modified retrospective method of adoption to all contracts as of the date of initial application. The financial impact to the consolidated financial statements as a result of adoption of the new standard is immaterial. Based on the nature of the contracts with our customers and our related performance obligations which transfer control, a $0.5 million after-tax cumulative-effect transition adjustment was made to increase the opening balance of Retained Earnings. We have included additional disclosures in the notes to the consolidated financial statements including additional information on the Company’s revenue streams and related performance obligations required to be satisfied in order to recognize revenue. (See *Revenue Recognition*.)

Practical Expedients

The following practical expedients were used by the Company as part of the adoption of the new revenue recognition guidance:

- We have a right to consideration from our customers in an amount that corresponds directly with the value to such customer for performance completed to date; therefore, we may recognize revenue in the amount to which we have a right to invoice.
- We do not adjust the promised amount of consideration for the effects of a significant financing component as at contract inception we expect that the period between when we transfer a promised good or service to a customer and when the customer pays for that good or service will be one year or less.
- Where applicable, we adopted this guidance using the portfolio approach in which contracts that have similar characteristics were reviewed as a portfolio. The effects on the financial statements of applying this guidance to the portfolio would not differ materially from applying the guidance to each individual contract.
- We recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that would otherwise have been recognized is one year or less.

Recently Issued Pronouncements

*Simplifying the Test for Goodwill Impairmen*t. In January 2017, the FASB issued updated guidance which simplifies the measurement of goodwill impairment by removing step two of the goodwill impairment test that requires the determination of the fair value of individual assets and liabilities of a reporting unit. The updated guidance requires goodwill impairment to be measured as the amount by which a reporting unit’s carrying value exceeds its fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for the Company beginning in the first quarter of 2020, with early adoption permitted on a prospective basis.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Leases. In 2016, the FASB issued an accounting standard update which revises the existing guidance for leases. Under the revised guidance, lessees will be required to recognize a “right-of-use” asset and a lease liability for all leases with a term greater than 12 months. The new standard also requires additional quantitative and qualitative disclosures by lessees and lessors to enable users of the financial statements to assess the amount, timing and uncertainty of cash flows arising from leases. The accounting for leases by lessors and the recognition, measurement, and presentation of expenses and cash flows from leases are not expected to significantly change as a result of the new guidance. As of December 31, 2018, the Company has reviewed all of its leases, completing our evaluation of the impact of this guidance. At adoption, we expect to recognize right-of-use assets and lease liabilities of approximately $36 million, which represents the discounted future minimum operating lease payments. The Company will adopt and implement the new guidance utilizing the additional optional transition method and package of practical expedients in the period of adoption without retrospective adjustment. Management continues to finalize additional qualitative and quantitative disclosures to meet the requirements of the new standard following adoption. The revised guidance is effective for the Company beginning in the first quarter of 2019.

Reclassification of Prior Income Statement. Beginning with the first quarter of 2018, the Company enhanced its presentation of Operating Revenue on the Consolidated Statement of Income by presenting the caption Operating Revenue separately as Contracts with Customers – Utility, Contracts with Customers – Non-utility, and Other – Non-utility. In conformity with the current presentation, we now present $1,063.8 million and $1,000.7 million of Operating Revenue as Contracts with Customers – Utility for the years ended December 31, 2017, and 2016, respectively, as it is generated from our regulated utility operations. Non-utility revenue of $331.9 million and $316.7 million as well as $23.6 million and $22.3 million for the years ended December 31, 2017, and 2016 respectively, is now presented as Contracts with Customers – Non-utility and Other – Non-utility, respectively.

Consolidated Statement of Income. In 2018, we recognized a $4.4 million reduction in revenue for MISO rates that were billed in 2017 and are expected to be credited to customers in 2019. We have evaluated the effect of this out-of-period adjustment on the years ended December 31, 2018, and 2017, and concluded that this adjustment is not material to any of the periods affected.

NOTE 2. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment **As of December 31**	**2018**	**2017**
Millions		
Regulated Operations		
Property, Plant and Equipment in Service	$4,490.6	$4,523.7
Construction Work in Progress	251.1	121.6
Accumulated Depreciation	(1,549.6)	(1,520.5)
Regulated Operations – Net	3,192.1	3,124.8
ALLETE Clean Energy		
Property, Plant and Equipment in Service	488.4	482.5
Construction Work in Progress	164.5	144.9
Accumulated Depreciation	(73.0)	(60.8)
ALLETE Clean Energy – Net	579.9	566.6
U.S. Water Services		
Property, Plant and Equipment in Service	30.1	24.8
Accumulated Depreciation	(14.0)	(10.4)
U.S. Water Services – Net	16.1	14.4
Corporate and Other *(a)*		
Property, Plant and Equipment in Service	214.3	204.7
Construction Work in Progress	6.6	5.0
Accumulated Depreciation	(104.6)	(93.1)
Corporate and Other – Net	116.3	116.6
Property, Plant and Equipment – Net	$3,904.4	$3,822.4

(a) Primarily includes BNI Energy and a small amount of non-rate base generation.

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets.

Estimated Useful Lives of Property, Plant and Equipment (Years)

Regulated Operations		ALLETE Clean Energy	5 to 35
Generation	5 to 50	U.S. Water Services	5 to 39
Transmission	52 to 71	Corporate and Other	3 to 50
Distribution	19 to 68		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction, development or normal operation of the asset. Asset retirement obligations (AROs) relate primarily to the decommissioning of our coal-fired and wind energy facilities, and land reclamation at BNI Energy. AROs are included in Other Non-Current Liabilities on the Consolidated Balance Sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

NOTE 2. PROPERTY, PLANT AND EQUIPMENT (Continued)

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, the period of remediation is indeterminable and removal liabilities have not been recognized.

Long-standing ratemaking practices approved by applicable state and federal regulatory authorities have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-AROs. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with GAAP for AROs. (See Note 4. Regulatory Matters.)

Asset Retirement Obligations

Millions	
Obligation as of December 31, 2016	$136.6
Accretion	7.6
Liabilities Settled	(5.9)
Revisions in Estimated Cash Flows	(15.6)
Obligation as of December 31, 2017	122.7
Accretion	7.0
Liabilities Settled	(5.3)
Revisions in Estimated Cash Flows	14.2
Obligation as of December 31, 2018	$138.6

NOTE 3. JOINTLY-OWNED FACILITIES AND ASSETS

Boswell Unit 4. Minnesota Power owns 80 percent of the 585 MW Boswell Unit 4. While Minnesota Power operates the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which it and WPPI Energy, the owner of the remaining 20 percent, have equal representation and voting rights. Each owner must provide its own financing and is obligated to its ownership share of operating costs. Minnesota Power’s share of operating expenses for Boswell Unit 4 is included in Operating Expenses on the Consolidated Statement of Income.

CapX2020. Minnesota Power was a participant in the CapX2020 initiative which represented an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consisted of electric cooperatives and municipal and investor-owned utilities, including Minnesota’s largest transmission owners, assessed the transmission system and projected growth in customer demand for electricity through 2020. Minnesota Power participated in certain CapX2020 projects which were completed and placed in service by 2015.

NOTE 3. JOINTLY-OWNED FACILITIES AND ASSETS (Continued)

Minnesota Power's investments in jointly-owned facilities and projects and the related ownership percentages are as follows:

Regulated Utility Plant	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
As of December 31, 2018				
Boswell Unit 4	$650.1	$229.9	$6.4	80
CapX2020	101.0	11.0	—	9.3 - 14.7
Total	$751.1	$240.9	$6.4	
As of December 31, 2017				
Boswell Unit 4	$668.2	$222.8	$8.2	80
CapX2020	101.0	8.4	—	9.3 - 14.7
Total	$769.2	$231.2	$8.2	

NOTE 4. REGULATORY MATTERS

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, PSCW or FERC. As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission, renewable and environmental investments and expenditures. (See *Transmission Cost Recovery Rider, Renewable Cost Recovery Rider* and *Environmental Improvement Rider*.) Revenue from cost recovery riders was $103.8 million in 2018 ($96.9 million in 2017; $97.1 million in 2016). With the implementation of final rates in Minnesota Power's general rate case, certain revenue previously recognized under cost recovery riders was incorporated into base rates. (See *2016 Minnesota General Rate Case.*)

2016 Minnesota General Rate Case. In November 2016, Minnesota Power filed a retail rate increase request with the MPUC which sought an average increase of approximately 9 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. The MPUC issued an order dated March 12, 2018, in Minnesota Power's general rate case approving a return on common equity of 9.25 percent and a 53.81 percent equity ratio. Final rates went into effect on December 1, 2018, which is expected to result in additional revenue of approximately $13 million on an annualized basis. Interim rates were collected from January 1, 2017, through November 30, 2018, which were fully offset by the recognition of a corresponding reserve. Minnesota Power has recorded a reserve for an interim rate refund, net of discounts provided to EITE customers, of $40.0 million as of December 31, 2018 ($23.7 million as of December 31, 2017) which is expected to be refunded in 2019. The MPUC also disallowed Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. As part of its decision in Minnesota Power's 2016 general rate case, the MPUC also extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050 primarily to mitigate rate increases for our customers, and shortened the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a net decrease to depreciation expense of approximately $25 million in the fourth quarter of 2017.

On April 2, 2018, Minnesota Power filed a petition with the MPUC requesting reconsideration of certain decisions in the MPUC's order dated March 12, 2018. In an order dated May 29, 2018, the MPUC denied Minnesota Power's petition for reconsideration and accepted a Minnesota Department of Commerce request for reconsideration reducing the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035 while utilizing the benefits of the lower federal income tax rate enacted as part of the TCJA to mitigate the impact on customer rates.

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

Energy-Intensive Trade-Exposed Customer Rates. An EITE customer ratemaking law was enacted in 2015 establishing a Minnesota energy policy to have competitive rates for certain industries such as mining and forest products. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an April 2017 order. Minnesota Power expects the discount to EITE customers to be approximately $16 million annually based on EITE customer current operating levels. While interim rates were in effect for Minnesota Power's 2016 general rate case, discounts provided to EITE customers offset interim rate refund reserves for non-EITE customers. Minnesota Power provided $16.7 million of discounts to EITE customers during the year ended December 31, 2018 ($8.6 million and none for the years ended December 31, 2017, and 2016, respectively).

FERC-Approved Wholesale Rates. Minnesota Power has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. All wholesale contracts include a termination clause requiring a three-year notice to terminate.

Minnesota Power's wholesale electric contract with the Nashwauk Public Utilities Commission is effective through at least December 31, 2032. No termination notice may be given for this contract prior to July 1, 2029. The wholesale electric service contracts with SWL&P and another municipal customer are effective through at least February 28, 2022, and through June 30, 2019, respectively. Under the agreement with SWL&P, no termination notice has been given. The other municipal customer provided termination notice for its contract in 2016. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. The rates included in these three contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to Minnesota Power's authorized rate of return for Minnesota retail customers. The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred.

Minnesota Power's wholesale electric contracts with 14 municipal customers are effective through varying dates ranging from 2024 through 2029. No termination notices may be given prior to three years before maturity. These contracts include fixed capacity charges through 2018; beginning in 2019, the capacity charge will be determined using a cost-based formula methodology with limits on the annual change from the previous year's capacity charge. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and will also be determined using a cost-based formula methodology.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider for certain transmission investments and expenditures. In a 2016 order, the MPUC approved Minnesota Power's updated customer billing rates which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. As a result of the MPUC approval of the certificate of need for the GNTL in 2015, the project is eligible for cost recovery under the existing transmission cost recovery rider. Minnesota Power is funding the construction of the GNTL with a subsidiary of Manitoba Hydro (see *Great Northern Transmission Line*), and anticipates including its portion of the investments and expenditures for the GNTL in future transmission bill factor filings.

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider for certain renewable investments and expenditures. The cost recovery rider allows Minnesota Power to charge retail customers on a current basis for the costs of certain renewable investments plus a return on the capital invested. Updated customer billing rates for the renewable cost recovery rider were approved by the MPUC in an order dated November 19, 2018.

Minnesota Power also has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. (See *Minnesota Solar Energy Standard.*) Currently, there is no approved customer billing rate for solar costs.

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

In a November 2016 order, the MPUC directed Minnesota Power to attribute all North Dakota investment tax credits realized from Bison to Minnesota Power regulated retail customers. As a result of the adverse regulatory outcome, Minnesota Power recorded a regulatory liability and a reduction in Operating Revenue of $15.0 million in 2016. The North Dakota investment tax credits previously recognized as income tax credits in Corporate and Other were reversed in 2016 resulting in an $8.8 million charge to net income in 2016. In December 2016, Minnesota Power submitted a request for reconsideration with the MPUC.

In a December 2017 order, the MPUC modified its November 2016 order to allow Minnesota Power to account for North Dakota investment tax credits based on the long-standing regulatory precedents of stand-alone allocation methodology of accounting for income taxes. As a result of the favorable regulatory outcome, Minnesota Power recorded a reduction in its regulatory liability and an increase in Operating Revenue of $14.0 million in 2017. The North Dakota investment tax credits previously recorded were reestablished as income tax credits in Corporate and Other, resulting in a $7.9 million increase to net income in 2017.

The stand-alone method provides that income taxes (and credits) are calculated as if Minnesota Power was the only entity included in ALLETE’s consolidated federal and unitary state income tax returns. Minnesota Power has recorded a regulatory liability for North Dakota investment tax credits generated by its jurisdictional activity and expected to be realized in the future. North Dakota investment tax credits attributable to ALLETE’s apportionment and income of ALLETE’s other subsidiaries are included in Corporate and Other operations.

Environmental Improvement Rider. Minnesota Power has an approved environmental improvement rider for investments and expenditures related to the implementation of the Boswell Unit 4 mercury emissions reduction plan completed in 2015. Updated customer billing rates for the environmental improvement rider were approved by the MPUC in an order dated November 19, 2018.

Fuel Adjustment Clause Reform. In a December 2017 order, the MPUC adopted a program to implement certain procedural reforms to the Minnesota utilities’ automatic fuel adjustment clause (FAC) for fuel and purchased power. The order will change the method of accounting for all Minnesota electric utilities to a monthly budgeted, forwarded-looking FAC with an annual prudence review and true-up to actual allowed costs. The MPUC is seeking input from Minnesota electric utilities and other stakeholders on the implementation and transition accounting needed to adopt the change. At a hearing on January 18, 2018, the MPUC disallowed recovery of Minnesota Power’s regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of the forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. In an order dated December 12, 2018, the MPUC deferred the implementation date to January 1, 2020.

Tax Cuts and Jobs Act of 2017. In December 2017, the MPUC opened a docket to review the effects of the TCJA on electric and natural gas rates and services in Minnesota, including the legislation’s impact on tax rates and utilities’ deferred income tax assets and liabilities. On March 2, 2018, Minnesota Power submitted an initial filing to the MPUC regarding the impacts of the TCJA on Minnesota Power. As part of Minnesota Power’s rate case, in an order dated May 29, 2018, the MPUC directed Minnesota Power to utilize the benefits of the lower federal income tax rate enacted as part of the TCJA to offset an increase in depreciation expense, effective January 1, 2018, resulting from the reduction in the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035 that would have otherwise resulted in an increase in customer rates. The impact of the TCJA on Minnesota Power’s deferred income tax assets and liabilities was not addressed in the rate case order.

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

In an order dated December 5, 2018, the MPUC determined the regulatory treatment for the impact of the TCJA on Minnesota Power's deferred income tax assets and liabilities. The MPUC authorized Minnesota Power to amortize the income tax benefits from the remeasurement of deferred income tax assets and liabilities resulting from the TCJA primarily over the life of the related property, plant and equipment with the remainder amortized over a 10-year period. The MPUC directed Minnesota Power to return these excess deferred income tax benefits as a monthly bill credit beginning with the implementation of final rates on December 1, 2018. Additionally, Minnesota Power customers will receive a one-time bill credit in 2019 for the benefit of the excess deferred income taxes from January 1, 2018, through November 30, 2018.

On January 10, 2018, the PSCW opened a docket to review the effects of the TCJA and directed Wisconsin utilities to defer its impacts until further direction was provided by the PSCW. In an order dated May 24, 2018, the PSCW directed SWL&P to refund the benefits of the lower federal income tax rates enacted as part of the TCJA on customer bills beginning in July 2018. In an order dated December 20, 2018, the PSCW directed SWL&P to return the excess deferred income tax benefits for 2018 in 2019 and 2020, and include the return of excess deferred income tax benefits going forward in final rates effective January 1, 2019, with a true-up in its next rate case. (See *2018 Wisconsin General Rate Case.*) These excess deferred income tax benefits for SWL&P will be returned primarily over the life of the related property, plant and equipment with the remainder amortized over a 4-year period.

2016 Wisconsin General Rate Case. SWL&P's retail rates in 2018 were based on a 2017 PSCW retail rate order effective August 2017 that allowed for a 10.5 percent return on common equity and a 55 percent equity ratio. SWL&P's retail rates prior to August 2017, were based on a 2012 PSCW retail rate order that provided for a 10.9 percent return on equity.

2018 Wisconsin General Rate Case. On May 25, 2018, SWL&P filed a rate increase request with the PSCW requesting an average increase of 2.7 percent for retail customers (2.0 percent increase in electric rates; 2.3 percent increase in natural gas rates; and 8.3 percent increase in water rates). The filing sought an overall return on equity of 10.5 percent and a 55.41 percent equity ratio. In an order dated December 20, 2018, the PSCW approved a rate increase for SWL&P including a return on equity of 10.4 percent and a 55.0 percent equity ratio. Final rates went into effect January 1, 2019, which is expected to result in additional revenue of approximately $1.3 million on an annualized basis.

Integrated Resource Plan. In 2015, Minnesota Power filed its 2015 IRP with the MPUC which included an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. The 2015 IRP also contained steps in Minnesota Power's *EnergyForward* strategic plan including the economic idling of Taconite Harbor Units 1 and 2 which occurred in 2016, the ceasing of coal-fired operations at Taconite Harbor in 2020, and the addition of between 200 MW and 300 MW of natural gas-fired generation. In a 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepted Minnesota Power's plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. Minnesota Power retired Boswell Units 1 and 2 in the fourth quarter of 2018.

NOTE 4. REGULATORY MATTERS (Continued)
Integrated Resource Plan (Continued)

In July 2017, Minnesota Power submitted a resource package to the MPUC requesting approval of PPAs for the output of a 250 MW wind energy facility and a 10 MW solar energy facility as well as approval of a 250 MW natural gas capacity dedication agreement. These agreements were subject to MPUC approval of the construction of NTEC, a 525 MW to 550 MW combined-cycle natural gas-fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE. Minnesota Power would purchase approximately 50 percent of the facility's output starting in 2025. In an order dated January 24, 2019, the MPUC approved Minnesota Power's request for approval of the NTEC natural gas capacity dedication agreement. Separately, the MPUC required a baseload retirement evaluation in Minnesota Power's next IRP filing analyzing its existing fleet including potential early retirement scenarios of Boswell Units 3 and 4, including a securitization plan. The MPUC also approved Minnesota Power's request to extend the next IRP filing deadline until October 1, 2020. On January 8, 2019, an application for a certificate of public convenience and necessity for NTEC was submitted to the PSCW. A decision on the application is expected in 2020.

On June 18, 2018, Minnesota Power filed a separate petition for approval of the PPA for the output of the 10 MW solar energy facility to be located in central Minnesota, which was approved by the MPUC in an order dated October 2, 2018. On August 22, 2018, Minnesota Power filed a separate petition for approval of an amended PPA for the output of the 250 MW wind energy facility to be located in southwestern Minnesota which was approved in an order dated January 23, 2019. (See Note 5. Equity Investments.)

Great Northern Transmission Line*.* Minnesota Power is constructing the GNTL, an approximately 220-mile 500-kV transmission line between Manitoba and Minnesota's Iron Range that was proposed by Minnesota Power and Manitoba Hydro. In a 2016 order, the MPUC approved the route permit for the GNTL, and in 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. To date, most of the right-of-way has been cleared while foundation installation and transmission tower construction have commenced. The total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, of which Minnesota Power's portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as non-shareholder contributions to capital. Total project costs of $380.8 million have been incurred through December 31, 2018, of which $203.7 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to the MMTP, a new transmission line in Canada that will connect with the GNTL. (See Note 11. Commitments, Guarantees and Contingencies.)

Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission cost recovery filings. (See *Transmission Cost Recovery Rider*.) Minnesota Power also has FERC approval to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers.

Conservation Improvement Program. Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues, excluding revenue received from exempt customers, from service provided in the state on energy CIPs each year. In November 2017, the Minnesota Department of Commerce approved Minnesota Power's modified CIP triennial filing for 2017 through 2019, which outlined Minnesota Power's CIP spending and energy-saving goals for those years. Minnesota Power's CIP investment goal was $10.3 million for 2018 ($10.3 million for 2017; $7.3 million for 2016), with actual spending of $9.0 million in 2018 ($8.1 million in 2017; $7.4 million in 2016). The investment goal for 2019 is $10.5 million.

NOTE 4. REGULATORY MATTERS (Continued)
Conservation Improvement Program (Continued)

On April 2, 2018, Minnesota Power submitted its 2017 CIP consolidated filing, which detailed Minnesota Power's CIP program results and requested a CIP financial incentive of $3.0 million based on MPUC procedures. In an order dated September 4, 2018, the MPUC approved Minnesota Power's CIP consolidated filing, including the requested CIP financial incentive which was recorded as revenue and as a regulatory asset in 2018. The approved financial incentive will be recovered in customer billing rates in 2018 and 2019. In 2017 and 2016, the CIP financial incentives recognize were $5.5 million and $7.5 million, respectively. CIP financial incentives are recognized in the period in which the MPUC approves the filing.

MISO Return on Equity Complaint. MISO transmission owners, including ALLETE and ATC, have an authorized return on equity of 10.32 percent, or 10.82 percent including an incentive adder for participation in a regional transmission organization.

In 2016, a federal administrative law judge ruled on a complaint proposing a reduction in the base return on equity to 9.70 percent, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending, which is not expected to have a material impact on our Consolidated Financial Statements.

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain customers, to be generated by solar energy by the end of 2020. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less and community solar garden subscriptions.

Minnesota Power's solar energy supply consists of Camp Ripley, a 10 MW solar energy facility at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, and a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. In an order dated October 2, 2018, the MPUC approved a PPA for the output of the 10 MW Blanchard solar energy facility to be located in central Minnesota. Minnesota Power expects that Camp Ripley, the community solar garden arrays, the PPA for the output of the 10 MW Blanchard solar energy facility, and an increase in solar rebates will allow Minnesota Power to meet both parts of the solar mandate.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to accounting guidance for the effect of certain types of regulation. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. With the exception of the regulatory asset for Boswell Units 1 and 2, no other regulatory assets are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable regulatory authority or over the corresponding period related to the asset or liability.

NOTE 4. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities **As of December 31**	**2018**	**2017**
Millions		
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans *(b)*	$218.5	$220.3
Income Taxes *(c)*	105.5	112.8
Asset Retirement Obligations *(d)*	32.6	29.6
Boswell 1 & 2 *(l)*	16.3	—
Manufactured Gas Plant *(e)*	8.0	8.1
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program *(f)*	—	3.3
Other	3.6	5.6
Total Non-Current Regulatory Assets	$389.5	$384.7
Current Regulatory Liabilities *(a)*		
Provision for Interim Rate Refund *(i)*	$40.0	—
Provision for Tax Reform Refund *(j)*	10.7	—
Transmission Formula Rates	4.4	—
Total Current Regulatory Liabilities	55.1	—
Non-Current Regulatory Liabilities		
Income Taxes *(c)*	396.4	$411.2
Wholesale and Retail Contra AFUDC *(h)*	64.4	57.9
Provision for Interim Rate Refund *(i)*	—	23.7
Plant Removal Obligations	25.1	20.3
North Dakota Investment Tax Credits *(k)*	14.7	14.1
Cost Recovery Riders *(g)*	6.9	2.2
Transmission Formula Rates	1.6	—
Other	3.0	2.6
Total Non-Current Regulatory Liabilities	512.1	532.0
Total Regulatory Liabilities	$567.2	$532.0

(a) Current regulatory liabilities are presented within Other Current Liabilities on the Consolidated Balance Sheet.

(b) Defined benefit pension and other postretirement items included in our Regulated Operations, which are otherwise required to be recognized in accumulated other comprehensive income as actuarial gains and losses as well as prior service costs and credits, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. (See Note 15. Pension and Other Postretirement Benefit Plans.)

(c) These costs represent the difference between deferred income taxes recognized for financial reporting purposes and amounts previously billed to our customers. The balances will primarily decrease over the remaining life of the related temporary differences and flow through current income taxes.

(d) Asset retirement obligations will accrete and be amortized over the lives of the related property with asset retirement obligations.

(e) The manufactured gas plant regulatory asset represents costs of remediation for a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. We expect recovery of these remediation costs to be allowed by the PSCW in rates over time.

(f) The conservation improvement program regulatory asset represents CIP expenditures, any financial incentive earned for cost-effective program achievements and a carrying charge deferred for future cost recovery over the next year following MPUC approval.

NOTE 4. REGULATORY MATTERS (Continued)

(g) The cost recovery rider regulatory liabilities are cash collections from our customers in excess of revenue recognized, primarily due to capital expenditures related to Bison, investment in CapX2020 projects, the Boswell Unit 4 environmental upgrade and the GNTL. The cost recovery rider regulatory liabilities as of December 31, 2018, will be returned within the next two years.

(h) Wholesale and retail contra AFUDC represents amortization to offset AFUDC Equity and Debt recorded during the construction period of our cost recovery rider projects prior to placing the projects in service. The regulatory liability will decrease over the remaining depreciable life of the related asset.

(i) This amount is expected to be refunded to Minnesota Power's regulated retail customers in 2019 and includes $23.8 million of discounts provided to EITE customers as of December 31, 2018, that will be offset against interim rate refunds ($8.6 million as of December 31, 2017). (See 2016 Minnesota General Rate Case and Energy-Intensive Trade-Exposed Customer Rates.)

(j) Provision for tax reform refund is expected to be refunded to Minnesota Power customers in the first quarter of 2019 and SWL&P customers in 2019 and 2020. (See Tax Cuts and Jobs Act of 2017.)

(k) North Dakota investment tax credits expected to be realized from Bison that will be credited to Minnesota Power's regulated retail customers through future renewable cost recovery rider filings as the tax credits are utilized.

(l) In December 2018, Minnesota Power retired Boswell Units 1 and 2 and reclassified the remaining net book value from property, plant and equipment to a regulatory asset on the Consolidated Balance Sheet. The remaining net book value is currently included in Minnesota Power's rate base and Minnesota Power is earning a return on the outstanding balance.

NOTE 5. EQUITY INVESTMENTS

Investment in ATC. Our wholly-owned subsidiary, ALLETE Transmission Holdings, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. We account for our investment in ATC under the equity method of accounting. As of December 31, 2018, our equity investment in ATC was $128.1 million ($118.7 million as of December 31, 2017). On January 31, 2019, we invested an additional $0.4 million in ATC. In total, we expect to invest approximately $8.5 million in 2019.

ALLETE's Investment in ATC

Year Ended December 31	**2018**	**2017**
Millions		
Equity Investment Beginning Balance	$118.7	$135.6
Cash Investments	6.2	7.8
Equity in ATC Earnings	17.5	22.5
Distributed ATC Earnings	(15.2)	(19.3)
Remeasurement of Deferred Income Taxes *(a)*	—	(27.9)
Amortization of the Remeasurement of Deferred Income Taxes	0.9	—
Equity Investment Ending Balance	$128.1	$118.7

(a) Impact of the remeasurement of deferred income tax assets and liabilities resulting from the TCJA.

NOTE 5. EQUITY INVESTMENTS (Continued)

ATC Summarized Financial Data

Balance Sheet Data **As of December 31**	**2018**	**2017**
Millions		
Current Assets	$87.2	$87.7
Non-Current Assets	4,928.8	4,598.9
Total Assets	$5,016.0	$4,686.6
Current Liabilities	$640.0	$767.2
Long-Term Debt	2,014.0	1,790.6
Other Non-Current Liabilities	295.3	240.3
Members' Equity	2,066.7	1,888.5
Total Liabilities and Members' Equity	$5,016.0	$4,686.6

Income Statement Data **Year Ended December 31**	**2018**	**2017**	**2016**
Millions			
Revenue	$690.5	$721.6	$650.8
Operating Expense	358.7	344.9	322.5
Other Expense	108.3	104.1	95.5
Net Income	$223.5	$272.6	$232.8
ALLETE's Equity in Net Income	$17.5	$22.5	$18.5

ATC's authorized return on equity is 10.32 percent, or 10.82 percent including an incentive adder for participation in a regional transmission organization.

In 2016, a federal administrative law judge ruled on a complaint proposing a reduction in the base return on equity to 9.70 percent, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending.

Investment in Nobles 2. On December 27, 2018, our wholly-owned subsidiary, ALLETE South Wind, entered into a partnership agreement with Tenaska to purchase a 49 percent equity interest in Nobles 2, the entity that will own and operate a 250 MW wind energy facility in southwestern Minnesota pursuant to a 20-year PPA with Minnesota Power. The wind energy facility will be built in Nobles County, Minnesota and is expected to be completed in late 2020, with an estimated total project cost of approximately $350 million to $400 million of which our portion is expected to be approximately $170 million to $200 million. We expect to utilize tax equity to finance a portion of our project costs, with an ALLETE expected equity investment of approximately $60 million to $70 million. We account for our investment in Nobles 2 under the equity method of accounting. As of December 31, 2018, our equity investment in Nobles 2 was $33.0 million.

NOTE 6. ACQUISITIONS

The following acquisitions are consistent with ALLETE's stated strategy of investing in energy infrastructure and related services businesses to complement its regulated businesses, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. The pro forma impact of the following acquisitions was not significant, either individually or in the aggregate, to the results of the Company for the years ended December 31, 2018, 2017 and 2016.

2017 Activity.

Tonka Water. In September 2017, U.S. Water Services acquired 100 percent of Tonka Water. Total consideration for the transaction was $19.2 million, including a working capital adjustment. Consideration of $19.0 million was paid in cash on the acquisition date and a working capital adjustment of $0.2 million was paid in the fourth quarter of 2017. Tonka Water is a supplier of municipal and industrial water treatment systems that expanded U.S. Water Services' geographic and customer markets.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2018, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis.

Millions	
Assets Acquired	
Accounts Receivable	$5.1
Other Current Assets	5.1
Trade Names *(a)*	0.9
Goodwill *(a)(b)*	16.9
Other Non-Current Assets	0.2
Total Assets Acquired	$28.2
Liabilities Assumed	
Current Liabilities	$9.0
Total Liabilities Assumed	$9.0
Net Identifiable Assets Acquired	$19.2

(a) Presented within Goodwill and Intangible Assets – Net on the Consolidated Balance Sheet. (See Note 7. Goodwill and Intangible Assets.)

(b) Recognized goodwill is attributable to the assembled workforce and anticipated synergies. For tax purposes, the purchase price allocation resulted in $4.1 million of deductible goodwill.

Acquisition-related costs were immaterial, expensed as incurred during 2017 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

2016 Activity.

Acquisition of Non-Controlling Interest. In 2016, ALLETE Clean Energy acquired the non-controlling interest in the limited liability company that owns its Condon wind energy facility for $8.0 million. This transaction was accounted for as an equity transaction, and no gain or loss was recognized in net income or other comprehensive income. As a result of the acquisition, the Condon wind energy facility is now a wholly-owned subsidiary of ALLETE Clean Energy.

NOTE 6. ACQUISITIONS (Continued)
2016 Activity (Continued)

WEST. In 2016, U.S. Water Services acquired 100 percent of Water & Energy Systems Technology of Nevada, Inc. (WEST). Total consideration for the transaction was $6.7 million. Consideration of $5.9 million was paid in cash on the acquisition date, working capital adjustments of $0.2 million were paid in 2017 and a $0.6 million payment was made in April 2018. WEST is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southwestern United States.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2017, is shown in the following table. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.1
Other Current Assets	1.0
Customer Relationships *(a)*	2.8
Goodwill *(a)(b)*	4.2
Other Non-Current Assets	0.1
Total Assets Acquired	$8.2
Liabilities Assumed	
Current Liabilities	$0.3
Non-Current Liabilities	1.2
Total Liabilities Assumed	$1.5
Net Identifiable Assets Acquired	$6.7

(a) Presented within Goodwill and Intangible Assets – Net on the Consolidated Balance Sheet. (See Note 7. Goodwill and Intangible Assets.)
(b) For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

Acquisition-related costs were immaterial, expensed as incurred during 2016 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

NOTE 7. GOODWILL AND INTANGIBLE ASSETS

The following table summarizes changes to goodwill by reportable segment:

	U.S. Water Services
Millions	
Balance as of December 31, 2016	$131.2
Acquired Goodwill *(a)*	16.9
Other Adjustments *(b)*	0.2
Balance as of December 31, 2017	148.3
Other Adjustments *(b)*	0.2
Balance as of December 31, 2018	$148.5

(a) See Note 6. Acquisitions.

(b) Finalization of purchase price accounting for U.S. Water Services' acquisition of WEST was completed in 2017 and acquisition of Tonka Water was completed in 2018 resulting in adjustments in those periods to the goodwill recorded at the time of acquisition.

The following table summarizes changes to intangible assets, net, for the year ended December 31, 2018:

	December 31, 2017	Additions	Amortization	December 31, 2018
Millions				
Intangible Assets				
Definite-Lived Intangible Assets				
Customer Relationships	$54.7	$0.2	$(4.2)	$50.7
Developed Technology and Other *(a)*	6.3	2.6	(1.4)	7.5
Total Definite-Lived Intangible Assets	61.0	2.8	(5.6)	58.2
Indefinite-Lived Intangible Assets				
Trademarks and Trade Names	16.6	—	n/a	16.6
Total Intangible Assets	$77.6	$2.8	$(5.6)	$74.8

(a) Developed Technology and Other includes patents, non-compete agreements, land easements and trade names with finite lives.

Customer relationships have a remaining useful life of approximately 19 years, and developed technology and other have remaining useful lives ranging from approximately 4 years to approximately 10 years (weighted average of approximately 6 years). The weighted average remaining useful life of all definite-lived intangible assets as of December 31, 2018, is approximately 17 years.

Amortization expense of intangible assets for the year ended December 31, 2018, was $5.6 million ($5.5 million in 2017; $5.2 million in 2016). Accumulated amortization was $20.4 million and $14.8 million as of December 31, 2018, and December 31, 2017, respectively. Estimated amortization expense for definite-lived intangible assets is $5.3 million in 2019, $4.9 million in 2020, $4.9 million in 2021, $4.6 million in 2022, $4.3 million in 2023 and $34.2 million thereafter.

NOTE 8. INVESTMENTS

Investments. As of December 31, 2018, the investment portfolio included the legacy real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held in other postretirement plans to fund employee benefits, the cash equivalents within these plans and other assets consisting primarily of land in Minnesota.

Other Investments

As of December 31	**2018**	**2017**
Millions		
ALLETE Properties	$24.4	$26.4
Available-for-sale Securities *(a)*	20.2	19.1
Cash Equivalents	1.0	3.8
Other	3.5	3.8
Total Other Investments	$49.1	$53.1

(a) As of December 31, 2018, the aggregate amount of available-for-sale corporate and governmental debt securities maturing in one year or less was $2.0 million, in one year to less than three years was $2.9 million, in three years to less than five years was $2.6 million, and in five or more years was $0.5 million.

Available-for-Sale Securities. We account for our available-for-sale securities portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits. Gross realized and unrealized gains and losses on our available-for-sale securities were immaterial in 2018, 2017 and 2016.

NOTE 9. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily equity securities.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation and fixed income securities.

NOTE 9. FAIR VALUE (Continued)

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes the U.S. Water Services contingent consideration liability.

The following tables set forth by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2018, and December 31, 2017. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy levels. The estimated fair value of Cash and Cash Equivalents listed on the Consolidated Balance Sheet approximates the carrying amount and therefore is excluded from the recurring fair value measures in the following tables.

	Fair Value as of December 31, 2018			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$12.2	—	—	$12.2
Available-for-sale – Corporate and Governmental Debt Securities	—	$8.0	—	8.0
Cash Equivalents	1.0	—	—	1.0
Total Fair Value of Assets	$13.2	$8.0	—	$21.2
Liabilities:				
Deferred Compensation *(b)*	—	$19.8	—	$19.8
U.S. Water Services Contingent Consideration *(c)*	—	—	$3.8	3.8
Total Fair Value of Liabilities	—	$19.8	$3.8	$23.6
Total Net Fair Value of Assets (Liabilities)	$13.2	$(11.8)	$(3.8)	$(2.4)

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Other Current Liabilities on the Consolidated Balance Sheet.

NOTE 9. FAIR VALUE (Continued)

	Fair Value as of December 31, 2017			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$10.2	—	—	$10.2
Available-for-sale – Corporate and Governmental Debt Securities	—	$8.9	—	8.9
Cash Equivalents	3.8	—	—	3.8
Total Fair Value of Assets	$14.0	$8.9	—	$22.9
Liabilities: *(b)*				
Deferred Compensation	—	$18.2	—	$18.2
U.S. Water Services Contingent Consideration	—	—	$5.4	5.4
Total Fair Value of Liabilities	—	$18.2	$5.4	$23.6
Total Net Fair Value of Assets (Liabilities)	$14.0	$(9.3)	$(5.4)	$(0.7)

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.

The following table provides a reconciliation of the beginning and ending balances of the U.S. Water Services Contingent Consideration measured at fair value using Level 3 measurements as of December 31, 2018, and December 31, 2017. The acquisition contingent consideration was recorded at the acquisition date at its estimated fair value. The acquisition date fair value was measured based on the consideration expected to be transferred, discounted to present value. The discount rate was determined at the time of measurement in accordance with generally accepted valuation methods. The fair value of the acquisition contingent consideration is remeasured to arrive at estimated fair value each reporting period with the change in fair value recognized as income or expense in the Consolidated Statement of Income. Changes to the fair value of the acquisition contingent consideration can result from changes in discount rates, timing of milestones that trigger payments, and the timing and amount of earnings estimates. Using different valuation assumptions, including earnings projections or discount rates, may result in different fair value measurements and expense (or income) in future periods. Management analyzes the fair value of the contingent liability on a quarterly basis and makes adjustments as appropriate. The acquisition contingent consideration was measured at $3.8 million as of December 31, 2018.

NOTE 9. FAIR VALUE (Continued)

Recurring Fair Value Measures

Activity in Level 3

Millions	
Balance as of December 31, 2016	$25.0
Accretion *(a)*	0.8
Payments *(b)*	(19.7)
Changes in Cash Flow Projections	(0.7)
Balance as of December 31, 2017	$5.4
Accretion *(a)*	0.4
Changes in Cash Flow Projections	(2.0)
Balance as of December 31, 2018	$3.8

(a) Included in Interest Expense on the Consolidated Statement of Income.

(b) Payments reflect the impact of a modification to the shareholder agreement in the first quarter of 2017 which provided participants a one-time election to sell shares at a determined price. Participants representing approximately half of the outstanding contingent consideration shares made the election, and were paid in 2017.

The Company's policy is to recognize transfers in and transfers out of Levels as of the actual date of the event or change in circumstances that caused the transfer. For the years ended December 31, 2018 and 2017, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed in the following table, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed in the following table was based on quoted market prices for the same or similar instruments (Level 2).

Financial Instruments	**Carrying Amount**	**Fair Value**
Millions		
Long-Term Debt, Including Long-Term Debt Due Within One Year		
December 31, 2018	$1,495.2	$1,534.6
December 31, 2017	$1,513.3	$1,627.6

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-financial assets such as equity method investments, goodwill, intangible assets, and property, plant and equipment are measured at fair value when there is an indicator of impairment and recorded at fair value only when an impairment is recognized.

Equity Method Investments. The aggregate carrying amount of our equity investments was $161.1 million as of December 31, 2018 ($118.7 million as of December 31, 2017). The Company assesses our equity investments in ATC and Nobles 2 for impairment whenever events or changes in circumstances indicate that the carrying amount of our investments may not be recoverable. For the years ended December 31, 2018 and 2017, there were no indicators of impairment. (See Note 5. Equity Investments.)

NOTE 9. FAIR VALUE (Continued)

Goodwill. The Company assesses the impairment of goodwill annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. The Company's goodwill is a result of the U.S. Water Services acquisition in 2015 as well as U.S. Water Services' subsequent acquisitions. (See Note 6. Acquisitions.) The aggregate carrying amount of goodwill was $148.5 million as of December 31, 2018, and $148.3 million as of December 31, 2017.

Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit's net assets exceeds the estimated fair value of the reporting unit. The inputs used in the fair value analysis fall within Level 3 of the fair value hierarchy due to the use of significant unobservable inputs to determine fair value. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. The Company calculates the excess of the reporting unit's fair value over its carrying amount, including goodwill, utilizing a discounted cash flow analysis. Our annual impairment test for U.S. Water Services indicated that the estimated fair value of U.S. Water Services exceeded its carrying value, and no impairment existed for the year ended December 31, 2018 (none in 2017 and none in 2016). As part of the 2016 annual impairment analysis, the Company recognized a non-cash impairment charge of $3.3 million for ALLETE Clean Energy's goodwill primarily related to the acquisition of Storm Lake II in 2014. The charge, which is presented within Operating Expenses – Other in the Consolidated Statement of Income, eliminated all goodwill for the ALLETE Clean Energy reporting unit. (See Note 1. Operations and Significant Accounting Policies.)

Intangible Assets. The Company assesses indefinite-lived intangible assets for impairment annually in the fourth quarter. The Company also assesses indefinite-lived and definite-lived intangible assets whenever events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable. Substantially all of the Company's intangible assets are a result of the U.S. Water Services acquisition in 2015 as well as U.S. Water Services' subsequent acquisitions. The aggregate carrying amount of intangible assets was $74.8 million as of December 31, 2018 ($77.6 million as of December 31, 2017). When events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable, the Company calculates the excess of an intangible asset's carrying amount over its undiscounted future cash flows. If the carrying amount is not recoverable, an impairment loss is recorded based on the amount by which the carrying amount exceeds the fair value. The inputs used in the fair value analysis fall within Level 3 of the fair value hierarchy due to the use of significant unobservable inputs to determine fair value. As of December 31, 2018, there have been no events or changes in circumstance which would indicate impairment of our intangible assets.

Property, Plant and Equipment. The Company assesses the impairment of property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of property, plant, and equipment assets may not be recoverable. The impairment of ALLETE Clean Energy's goodwill in 2016, primarily due to lower estimated energy prices in periods not under PSAs, caused management to review ALLETE Clean Energy's WTGs for impairment. Based on the results of the undiscounted cash flow analysis, the undiscounted future cash flows were adequate to recover the carrying value of the WTGs. (See Note 1. Operations and Significant Accounting Policies.) For the years ended December 31, 2018, and 2017, there was no impairment of property, plant, and equipment.

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. In a 2016 order, the MPUC accepted Minnesota Power's plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. Minnesota Power retired Boswell Units 1 and 2 in the fourth quarter of 2018. As part of the 2016 general retail rate case, the MPUC allowed recovery of the remaining book value of Boswell Units 1 and 2 through 2022. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3, ceasing of coal-fired operations at Taconite Harbor Units 1 and 2 or the conversion of Laskin to operate on natural gas. In addition, we expect to be able to continue depreciating these assets for at least their established remaining useful lives; however, we are unable to predict the impact of regulatory outcomes resulting in changes to their established remaining useful lives. (See Note 4. Regulatory Matters.)

NOTE 10. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of December 31, 2018, total short-term debt outstanding was $57.5 million ($64.1 million as of December 31, 2017), consisted of long-term debt due within one year and included $0.4 million of unamortized debt issuance costs.

As of December 31, 2018, we had consolidated bank lines of credit aggregating $407.0 million ($407.0 million as of December 31, 2017), most of which expire in January 2024. We had $18.4 million outstanding in standby letters of credit and no outstanding draws under our lines of credit as of December 31, 2018 ($11.9 million in standby letters of credit and no outstanding draws as of December 31, 2017).

On January 10, 2019, ALLETE entered into an amended and restated $400 million credit agreement (Credit Agreement). The Credit Agreement amended and restated ALLETE's $400 million credit facility, which was scheduled to expire in October 2020. The Credit Agreement is unsecured, has a variable interest rate and will expire in January 2024. At ALLETE's request and subject to certain conditions, the Credit Agreement may be increased by up to$150 million and ALLETE may make two requests to extend the maturity date, each for a one-year extension. Advances may be used by ALLETE for general corporate purposes, to provide liquidity in support of ALLETE's commercial paper program and to issue up to $60 million in letters of credit.

Long-Term Debt. As of December 31, 2018, total long-term debt outstanding was $1,428.5 million ($1,439.2 million as of December 31, 2017) and included $8.8 million of unamortized debt issuance costs. The aggregate amount of long-term debt maturing in 2019 is $57.9 million; $113.7 million in 2020; $98.5 million in 2021; $89.3 million in 2022; $88.5 million in 2023; and $1,047.3 million thereafter. Substantially all of our regulated electric plant is subject to the lien of the mortgages collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

Minnesota Power is obligated to make financing payments for the Camp Ripley solar array totaling $1.4 million annually during the financing term, which expires in 2027. Minnesota Power has the option at the end of the financing term to renew for a two-year term, or to purchase the solar array for approximately $4 million. Minnesota Power anticipates exercising the purchase option when the term expires.

On April 16, 2018, ALLETE issued and sold $60.0 million of its First Mortgage Bonds (the Bonds) that bear interest at 4.07 percent. The Bonds will mature in April 2048 and pay interest semi-annually in April and October of each year, commencing on October 16, 2018. ALLETE has the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for these types of transactions. ALLETE intends to use the proceeds from the sale of the Bonds to fund utility capital investment and for general corporate purposes. The Bonds were sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

On October 3, 2018, and October 17, 2018, ALLETE repaid $20.0 million and $10.0 million, respectively, under an unsecured term loan due in 2020.

NOTE 10. SHORT-TERM AND LONG-TERM DEBT (Continued)
Long-Term Debt (Continued)

Long-Term Debt As of December 31	2018	2017
Millions		
First Mortgage Bonds		
1.83% Series Due 2018	—	$50.0
8.17% Series Due 2019	$42.0	42.0
5.28% Series Due 2020	35.0	35.0
2.80% Series Due 2020	40.0	40.0
4.85% Series Due 2021	15.0	15.0
3.02% Series Due 2021	60.0	60.0
3.40% Series Due 2022	75.0	75.0
6.02% Series Due 2023	75.0	75.0
3.69% Series Due 2024	60.0	60.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
3.20% Series Due 2026	75.0	75.0
5.99% Series Due 2027	60.0	60.0
3.30% Series Due 2028	40.0	40.0
3.74% Series Due 2029	50.0	50.0
3.86% Series Due 2030	60.0	60.0
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
4.08% Series Due 2042	85.0	85.0
4.21% Series Due 2043	60.0	60.0
4.95% Series Due 2044	40.0	40.0
5.05% Series Due 2044	40.0	40.0
4.39% Series Due 2044	50.0	50.0
4.07% Series Due 2048	60.0	—
Variable Demand Revenue Refunding Bonds Series 1997 A Due 2020	13.5	13.5
Unsecured Term Loan Variable Rate Due 2020	10.0	40.0
Armenia Mountain Senior Secured Notes 3.26% Due 2024	57.2	65.9
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006, Due 2025	27.8	27.8
Senior Unsecured Notes 3.11% Due 2027	80.0	80.0
SWL&P First Mortgage Bonds 4.15% Series Due 2028	15.0	15.0
SWL&P First Mortgage Bonds 4.14% Series Due 2048	12.0	—
Other Long-Term Debt, 3.11% – 5.75% Due 2019 – 2037	67.7	69.1
Unamortized Debt Issuance Costs	(9.2)	(10.0)
Total Long-Term Debt	1,486.0	1,503.3
Less: Due Within One Year	57.5	64.1
Net Long-Term Debt	$1,428.5	$1,439.2

NOTE 10. SHORT-TERM AND LONG-TERM DEBT (Continued)

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive financial covenant requires ALLETE to maintain a ratio of indebtedness to total capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00, measured quarterly. As of December 31, 2018, our ratio was approximately 0.41 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. ALLETE has no significant restrictions on its ability to pay dividends from retained earnings or net income. As of December 31, 2018, ALLETE was in compliance with its financial covenants.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The following table details the estimated minimum payments for certain long-term commitments:

As of December 31, 2018

Millions	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**
Coal, Rail and Shipping Contracts	$20.8	$9.0	$7.5	—	—	—
Operating Leases	$9.9	$7.9	$6.1	$4.9	$3.1	$9.4
Easements	$4.8	$4.9	$4.9	$5.0	$5.1	$136.3
Other *(a)*	$31.6	$0.3	$0.3	—	—	$0.1
PPAs *(b)*	$107.3	$115.3	$145.4	$145.7	$145.8	$1,550.7

(a) Consists of long-term service agreements for wind energy facilities.

(b) Does not include the agreement with Manitoba Hydro expiring in 2022, as this contract is for surplus energy only; Oliver Wind I and Oliver Wind II, as Minnesota Power only pays for energy as it is delivered; and the agreement with Nobles 2 commencing in 2020 as it is subject to construction of a wind energy facility. (See Power Purchase Agreements.)

Power Purchase and Sales Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPAs, or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to capacity and energy payments.

These agreements have also been evaluated under the accounting guidance for derivatives. We have determined that either these agreements are not derivatives, or if they are derivatives, the agreements qualify for the normal purchases and normal sales exemption to the accounting guidance; therefore, derivative accounting is not required.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase and Sales Agreements (Continued)

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on its entitlement to the output of Square Butte's 455 MW coal-fired generating unit. Minnesota Power's output entitlement under the Agreement is 50 percent for the remainder of the Agreement, subject to the provisions of the Minnkota Power PSA described in the following table. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of December 31, 2018, Square Butte had total debt outstanding of $304.0 million. Annual debt service for Square Butte is expected to be approximately $48.7 million in each of the next five years, 2019 through 2023, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through Minnesota Power's fuel adjustment clause and include the cost of coal purchased from BNI Energy under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2018 was $78.0 million ($75.7 million in 2017; $73.3 million in 2016). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $9.1 million in 2018 ($9.4 million in 2017; $9.6 million in 2016). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase and Sales Agreements (Continued)

Minnesota Power has also entered into the following PPAs for the purchase or sale of capacity and energy as of December 31, 2018:

Counterparty	Quantity	Product	Commencement	Expiration	Pricing
PPAs					
Calpine Corporation	25 MW	Capacity	June 2019	May 2026	Fixed
Cypress Creek Renewables *(a)*	*(a)*	Capacity / Energy	*(a)*	*(a)*	Fixed
Great River Energy					
PPA 1	50 MW	Capacity / Energy	June 2016	May 2020	*(b)*
PPA 2	50 MW	Capacity	June 2016	May 2020	Fixed
PPA 3	50 MW	Capacity	June 2017	May 2020	Fixed
Manitoba Hydro					
PPA 1	*(c)*	Energy	May 2011	April 2022	Forward Market Prices
PPA 2	50 MW	Capacity / Energy	June 2015	May 2020	*(d)*
PPA 3	50 MW	Capacity	June 2017	May 2020	Fixed
PPA 4 *(e)*	250 MW	Capacity / Energy	June 2020	May 2035	*(f)*
PPA 5 *(e)*	133 MW	Energy	*(g)*	*(g)*	Forward Market Prices
Minnkota Power	50 MW	Capacity / Energy	June 2016	May 2020	*(h)*
Nobles 2 *(i)*	*(i)*	Capacity / Energy	*(i)*	*(i)*	Fixed
Oliver Wind I	*(j)*	Energy	December 2006	December 2040	Fixed
Oliver Wind II	*(j)*	Energy	December 2007	December 2040	Fixed
Shell Energy	50 MW	Energy	January 2017	December 2019	Fixed
TransAlta	*(k)*	Energy	January 2017	December 2019	Fixed

(a) The PPA provides for the purchase of all output from the 10 MW Blanchard solar energy facility to be located in central Minnesota. Construction of the Blanchard solar energy facility is expected to be completed in 2020 and the contract is effective for 25 years beginning upon commercial operation.

(b) The capacity price is fixed and the energy price is based on a formula that includes an annual fixed price component adjusted for changes in a natural gas index, as well as market prices.

(c) The energy purchased consists primarily of surplus hydro energy on Manitoba Hydro's system and is delivered on a non-firm basis. Minnesota Power will purchase at least one million MWh of energy over the contract term.

(d) The capacity and energy prices are adjusted annually by the change in a governmental inflationary index.

(e) Agreements are subject to the construction of the GNTL and MMTP. (See Great Northern Transmission Line.)

(f) The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

(g) The contract term will be the 20-year period beginning on the in-service date for the GNTL. (See Great Northern Transmission Line.)

(h) The agreement includes a fixed capacity charge and energy prices that escalate at a fixed rate annually over the term.

(i) The PPA provides for the purchase of all output from a 250 MW wind energy facility to be constructed in southwest Minnesota for 20 years beginning upon commercial operation of the wind energy facility which is currently expected in fourth quarter of 2020. (See Note 4. Regulatory Matters and Note 5. Equity Investments.)

(j) The PPAs provide for the purchase of all output from the 50 MW Oliver Wind I and 48 MW Oliver Wind II wind energy facilities.

(k) Minnesota Power is purchasing 50 MW of energy during off-peak hours and 100 MW of energy during on-peak hours.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase and Sales Agreements (Continued)

Minnesota Power has also entered into the following PSAs for the purchase or sale of capacity and energy as of December 31, 2018:

Counterparty	Quantity	Product	Commencement	Expiration	Pricing
PSAs					
Basin					
PSA 1	100 MW	Capacity / Energy	May 2010	April 2020	*(a)*
PSA 2	50 MW	Capacity	June 2017	May 2019	Fixed
PSA 3	*(b)*	Capacity	June 2022	May 2025	Fixed
PSA 4	100 MW	Capacity	June 2025	May 2028	Fixed
Minnkota Power	*(c)*	Capacity / Energy	June 2014	December 2026	*(c)*
Oconto Electric Cooperative	25 MW	Capacity / Energy	January 2019	May 2026	Fixed
Silver Bay Power	*(d)*	Energy	January 2017	December 2031	*(e)*

(a) The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on the cost of fuel. The agreement also allows Minnesota Power to recover a pro rata share of increased costs related to emissions that occur during the last five years of the contract.

(b) The agreement provides for 75 MW of capacity from June 1, 2022, through May 31, 2023, and increases to 125 MW of capacity from June 1, 2023, through May 31, 2025.

(c) Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025. Of Minnesota Power's 50 percent output entitlement, it sold to Minnkota Power approximately 28 percent in 2018 (28 percent in 2017 and in 2016). (See Square Butte PPA.)

(d) Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power, which has been served predominately through self-generation by Silver Bay Power. Through 2019, Minnesota Power will supply Silver Bay Power with at least 50 MW of energy and Silver Bay Power has the option to purchase additional energy. By December 31, 2019, Silver Bay Power is expected to cease self-generation and Minnesota Power is expected to supply the energy requirements for Silver Bay Power.

(e) The energy pricing is fixed through 2019 with pricing in later years escalating at a fixed rate annually and adjusted for changes in a natural gas index.

Coal, Rail and Shipping Contracts. Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2019 and a portion of its coal requirements through December 2021. Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2021. The costs of fuel and related transportation costs for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Leasing Agreements. BNI Energy is obligated to make lease payments for a dragline totaling $2.8 million annually during the lease term, which expires in 2027. BNI Energy has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We also lease other properties and equipment under operating lease agreements with a majority of terms expiring through 2024. Total lease expense was $14.6 million in 2018 ($17.5 million in 2017; $17.1 million in 2016).

Transmission. We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include the GNTL, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others) and our investment in ATC.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Transmission (Continued)

Great Northern Transmission Line. As a condition of a 250 MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power is constructing the GNTL, an approximately 220-mile 500-kV transmission line between Manitoba and Minnesota's Iron Range that was proposed by Minnesota Power and Manitoba Hydro in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

In a 2016 order, the MPUC approved the route permit for the GNTL, and in 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. To date, most of the right-of-way has been cleared while foundation installation and transmission tower construction have commenced. The total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, of which Minnesota Power's portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as non-shareholder contributions to capital. Total project costs of $380.8 million have been incurred through December 31, 2018, of which $203.7 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to the MMTP, a new transmission line in Canada that will connect with the GNTL. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the MMTP to the Manitoba Conservation and Water Stewardship for siting and environmental approval, which remains pending. In 2016, Manitoba Hydro filed an application with the Canadian National Energy Board (NEB) requesting authorization to construct and operate the MMTP, which was recommended for approval on November 15, 2018. Approval of the Canadian federal cabinet is also required.

The MMTP is subject to legal and regulatory challenges which Minnesota Power is actively monitoring. Manitoba Hydro has informed Minnesota Power that it continues to work towards completing the MMTP on schedule. In order to meet the transmission in-service requirements in PPAs with Minnesota Power, Manitoba Hydro has indicated that it would need to start construction of the MMTP by June 2019. We are unable to predict the outcome of the Canadian regulatory review process, including the timing thereof or whether any onerous conditions may be imposed, or the timing of the completion of the MMTP, including the impact of any delays that may result in construction schedule adjustments. Any significant delays in the MMTP construction schedule may result in Minnesota Power adjusting the GNTL construction schedule and impact the timing of capital expenditures and associated cost recovery under our transmission cost recovery rider.

Construction of Manitoba Hydro's Keeyask hydroelectric generation facility, which will provide the power to be sold under PPAs with Minnesota Power and transmitted on the MMTP and the GNTL, commenced in 2014 and is anticipated to be in service by early 2021.

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have been promulgated by both the EPA and state authorities over the past several years. Minnesota Power's facilities are subject to additional requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits have been obtained. We anticipate that with many state and federal environmental regulations and requirements finalized, or to be finalized in the near future, potential expenditures for future environmental matters may be material and require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of environmental regulations to project power supply trends and impacts on customers.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers.

Air. The electric utility industry is regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, baghouses and low NO_X technologies. Under currently applicable environmental regulations, these facilities are substantially compliant with emission requirements.

New Source Review (NSR). In 2014, Minnesota Power reached a settlement with the EPA and entered into a Consent Decree regarding certain Notices of Violation received in 2008 and 2011 that asserted violations of the NSR requirements of the Clean Air Act, which was approved by the U.S. District Court for the District of Minnesota. The Consent Decree provided for, among other requirements, more stringent emissions limits at all affected units, the option of refueling, retrofitting or retiring certain small coal units, and the addition of 200 MW of wind energy. Provisions of the Consent Decree require that, by no later than December 31, 2018, Boswell Units 1 and 2 must be retired, refueled, repowered, or emissions rerouted through existing emission control technology at Boswell. Minnesota Power retired Boswell Units 1 and 2 in the fourth quarter of 2018. Minnesota Power is allowed to recover the remaining net book value for Boswell Units 1 and 2 through 2022. We believe that costs to retire Boswell Units 1 and 2 will be eligible for recovery in rates over time, subject to regulatory approval in a rate proceeding.

Mercury and Air Toxics Standards (MATS) Rule. Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The final MATS rule addressed such emissions from coal-fired utility units greater than 25 MW and established categories of HAPs, including mercury, trace metals other than mercury, and acid gases. The EPA established emission limits for these categories of HAPs and work practice standards for the remaining categories. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan to position the unit for MATS compliance was completed in 2015. Investments and compliance work previously completed at Boswell Unit 3, including emission reduction investments completed in 2009, meet the requirements of the MATS rule. The conversion of Laskin Units 1 and 2 to operate on natural gas in 2015 positioned those units for MATS compliance. On December 27, 2018, the EPA issued a proposed revised Supplemental Cost Finding for MATS that determined it is not appropriate and necessary to regulate HAP emissions from power plants under section 112 of the Clean Air Act.

Minnesota Mercury Emissions Reduction Act/Rule. Minnesota Power was required to implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above (see *Mercury and Air Toxics Standards (MATS) Rule*) fulfills the requirements of the Minnesota Mercury Emissions Reduction Act.

Cross-State Air Pollution Rule (CSAPR). The CSAPR requires certain states in the eastern half of the U.S., including Minnesota, to reduce power plant emissions that contribute to ozone or fine particulate pollution in other states. The CSAPR does not require installation of controls but does require facilities have sufficient allowances to cover their emissions on an annual basis. These allowances are allocated to facilities from each state's annual budget, and can be bought and sold. Based on our review of the NO_X and SO_2 allowances issued and pending issuance, we currently expect generation levels and emission rates will result in continued compliance with the CSAPR.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with the NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. None of the compliance costs for proposed or current NAAQS revisions are expected to be material.

Climate Change. The scientific community generally accepts that emissions of GHG are linked to global climate change which creates physical and financial risks. Physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and changes in the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. We are addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expanding renewable power supply for both our operations and the operations of others;
- Providing energy conservation initiatives for our customers and engaging in other demand side management efforts;
- Improving efficiency of our generating facilities;
- Supporting research of technologies to reduce carbon emissions from generating facilities and carbon sequestration efforts;
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas-fired generating facilities;
- Managing vegetation on right-of-way corridors to reduce potential wildfire or storm damage risks; and
- Practicing sound forestry management in our service territories to create landscapes more resilient to disruption from climate-related changes, including planting and managing long-lived conifer species.

EPA Regulation of GHG Emissions. In 2014, the EPA announced a proposed rule under Section 111(d) of the Clean Air Act for existing power plants entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units", also referred to as the Clean Power Plan (CPP). The EPA issued the final CPP in 2015, together with a proposed federal implementation plan and a model rule for emissions trading. In 2016, the U.S. Supreme Court issued an order staying the effectiveness of the rule until after the appellate court process is complete. In 2016, the U.S. Court of Appeals for the District of Columbia Circuit heard oral arguments and is currently deliberating. If the CPP is upheld at the completion of the appellate process, all of the CPP regulatory deadlines are expected to be reset based on the length of time that the appeals process takes. The EPA is precluded from enforcing the CPP while the U.S. Supreme Court stay is in force.

If upheld, the CPP would establish uniform CO_2 emission performance rates for existing fossil fuel-fired and natural gas-fired combined cycle generating units, setting state-specific goals for CO_2 emissions from the power sector. State goals were determined based on CPP source-specific performance emission rates and each state's mix of power plants. The EPA filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit to hold CPP-related litigation in suspension while the EPA is reviewing the rule. In October 2017, the EPA issued a notice of proposed rulemaking, proposing to repeal the CPP. In December 2017, an Advanced Notice of Proposed Rulemaking for a CPP replacement rule was published in the Federal Register.

On August 31, 2018, the EPA published the proposed Affordable Clean Energy Rule in the Federal Register, which is intended to replace the CPP with revised emission guidelines that inform the development, submittal, and implementation of State Implementation Plans (SIP) to reduce GHG emissions for existing steam generating units. If a state does not submit a SIP or submits a plan that is unacceptable to the EPA, the EPA would develop a Federal Implementation Plan (FIP). Minnesota Power generating facilities affected by this proposal include Boswell, Laskin, Taconite Harbor and Hibbard.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

The proposed Affordable Clean Energy Rule seeks to reduce carbon intensity at existing steam generation units by prescribing Best System of Emission Reduction (BSER), primarily through Heat Rate Improvement (HRI) technologies. Under the proposal, states will have up to three years to develop a SIP, which is subject to EPA approval. While many of the HRIs proposed by the EPA in the proposed rule have already been installed in Minnesota Power's largest coal-fired generating units, compliance specifics would be detailed in either Minnesota's SIP or a FIP.

Minnesota has already initiated several measures consistent with those called for under the CPP and proposed Affordable Clean Energy Rule. Minnesota Power is implementing its *EnergyForward* strategic plan that provides for significant emission reductions and diversifying its electricity generation mix to include more renewable and natural gas energy. (See Note 6. Regulatory Matters.) We are unable to predict the GHG emission compliance costs we might incur; however, the costs could be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Water. The Clean Water Act requires NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations.

Steam Electric Power Generating Effluent Limitations Guidelines. In 2015, the EPA issued revised federal effluent limitation guidelines (ELG) for steam electric power generating stations under the Clean Water Act. It set effluent limits and prescribed BACT for several wastewater streams, including flue gas desulphurization (FGD) water, bottom ash transport water and coal combustion landfill leachate. In September 2017, the EPA announced a two-year postponement of the ELG compliance date of November 1, 2018, to November 1, 2020, while the agency reconsiders the bottom ash transport water and FGD wastewater provisions.

The final ELG rule's potential impact on Minnesota Power operations is primarily at Boswell. Boswell currently discharges bottom ash contact water through its NPDES permit, and also has a closed-loop FGD system that does not discharge to surface waters, but may do so in the future. Under the existing ELG rule, bottom ash transport water discharge to surface waters must cease no later than December 31, 2023. Bottom ash contact water will either need to be re-used in a closed-loop process, routed to a FGD scrubber, or the bottom ash handling system will need to be converted to a dry process. If FGD wastewater is discharged in the future, it will require additional wastewater treatment. The ELG rule provision regarding these two waste-streams are being reconsidered and may change prior to November 1, 2020. Efforts have been underway at Boswell to reduce the amount of water discharged and evaluate potential re-use options in its plant processes.

At this time, we cannot estimate what compliance costs we might incur related to these or other potential future water discharge regulations; however, the costs could be material, including costs associated with retrofits for bottom ash handling, pond dewatering, pond closure, and wastewater treatment and re-use. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit reports to the EPA.

Coal Ash Management Facilities. Minnesota Power stores or disposes coal ash at four of its electric generating facilities by the following methods: storing ash in lined onsite impoundments (ash ponds), disposing of dry ash in a lined dry ash landfill, applying ash to land as an approved beneficial use and trucking ash to state permitted landfills.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Coal Combustion Residuals from Electric Utilities (CCR). In 2015, the EPA published the final rule regulating CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) in the Federal Register. The rule includes additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. Costs of compliance for Boswell and Laskin are expected to occur primarily over the next 15 years and be between approximately $65 million and $120 million. The EPA has indicated to Minnesota Power that the landfill at Taconite Harbor, which has been idled and has a temporary landfill cover in place, is a CCR unit based on the EPA's interpretation of the CCR rule language. Minnesota Power has agreed to post the required CCR information for the Taconite Harbor landfill on Minnesota Power's website while the CCR issue is resolved. Compliance costs for CCR at Taconite Harbor are not expected to be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Minnesota Power continues to work on minimizing costs through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. In September 2017, the EPA announced its intention to formally reconsider the CCR rule under Subtitle D of the RCRA and on March 15, 2018, published the first phase of the proposed rule revisions in the Federal Register. On July 17, 2018, the EPA finalized revisions to elements of the CCR rule, including extending certain deadlines by two years, the establishment of alternative groundwater protection standards for certain constituents and the potential for risk-based management options at facilities based on site characteristics. On August 22, 2018, a U.S. District Court for the District of Columbia decision vacated specific provisions of the CCR rule. The court decision changes the status of three existing impoundments at Boswell that must now be considered unlined. Compliance costs at Boswell due to the court decision are unknown at this time. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Other Environmental Matters

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. SWL&P has been working with the Wisconsin Department of Natural Resources (WDNR) in determining the extent and location of contamination at the site and surrounding properties. In December 2017, the WDNR authorized SWL&P to transition from site investigation into the remedial design process. As of December 31, 2018, we have recorded a liability of approximately $7 million for remediation costs at this site (approximately $8 million as of December 31, 2017), and an associated regulatory asset as we expect recovery of these remediation costs to be allowed by the PSCW. We expect to incur these costs over the next four years.

Other Matters

ALLETE Clean Energy. ALLETE Clean Energy's wind energy facilities have PSAs in place for their entire output and expire in various years between 2019 and 2032. As of December 31, 2018, ALLETE Clean Energy has $21.0 million outstanding in standby letters of credit.

U.S. Water Services. As of December 31, 2018, U.S. Water Services has no outstanding standby letters of credit.

BNI Energy. As of December 31, 2018, BNI Energy had surety bonds outstanding of $49.9 million and a letter of credit for an additional $0.6 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although its coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. BNI Energy's total reclamation liability is currently estimated at $47.5 million. BNI Energy does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Other Matters (Continued)

ALLETE Properties. As of December 31, 2018, ALLETE Properties had surety bonds outstanding and letters of credit to governmental entities totaling $8.6 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is $6.1 million. ALLETE Properties does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

Community Development District Obligations. In 2005, the Town Center District issued $26.4 million of tax-exempt, 6.0 percent capital improvement revenue bonds, and in 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and are secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in 2006 for the Town Center District and 2007 for the Palm Coast Park District. To the extent that ALLETE Properties still owns land at the time of the assessment, it will incur the cost of its portion of these assessments, based upon its ownership of benefited property.

As of December 31, 2018, we owned 68 percent of the assessable land in the Town Center District (70 percent as of December 31, 2017) and 19 percent of the assessable land in the Palm Coast Park District (33 percent as of December 31, 2017). As of December 31, 2018, ownership levels, our annual assessments related to capital improvement and special assessment bonds for the ALLETE Properties projects within these districts are $1.4 million for Town Center at Palm Coast and $0.6 million for Palm Coast Park. As we sell property at these projects, the obligation to pay special assessments will pass to the new landowners. In accordance with accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, and compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

U.S. Water Services is involved in on-going patent defense litigation it brought against a company for infringement of two patents held by U.S. Water Services. As of December 31, 2018, U.S. Water Services has recognized approximately $2.6 million of patent defense costs as an intangible asset. Management expects that U.S. Water Services will prevail, but in the event of an unfavorable outcome, the patent defense costs would be recognized as an expense in the period of resolution.

NOTE 12. COMMON STOCK AND EARNINGS PER SHARE

Summary of Common Stock	Shares Thousands	Equity Millions
Balance as of December 31, 2015	49,075	$1,271.4
Employee Stock Purchase Plan	16	0.9
Invest Direct	344	20.0
Options and Stock Awards	65	3.7
Contributions to RSOP	60	3.3
Equity Issuance Program	130	8.0
Received for Sale of Land Inventory	(130)	(8.0)
Acquisition of Non-Controlling Interest	—	(4.0)
Balance as of December 31, 2016	49,560	1,295.3
Employee Stock Purchase Plan	12	0.8
Invest Direct	257	19.0
Options and Stock Awards	22	3.6
Contributions to RSOP	50	3.5
Equity Issuance Program	1,000	65.7
Contribution to Pension	216	13.5
Balance as of December 31, 2017	51,117	1,401.4
Employee Stock Purchase Plan	11	0.8
Invest Direct	277	20.7
Options and Stock Awards	57	2.1
Contributions to RSOP	47	3.5
Balance as of December 31, 2018	51,509	$1,428.5

Equity Issuance Program. We entered into a distribution agreement with Lampert Capital Markets, Inc., in 2008, as amended most recently in 2016, with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 2.9 million shares remain available for issuance as of December 31, 2018. For the year ended December 31, 2018, no shares of common stock were issued under this agreement (1.0 million shares for net proceeds of $65.7 million in 2017; 0.1 million shares for net proceeds of $8.0 million in 2016). The shares issued in 2017 and 2016 were offered and sold pursuant to Registration Statement No. 333-212794, pursuant to which the remaining shares will continue to be offered for sale, from time to time.

Contributions to Pension. For the year ended December 31, 2018, we contributed no shares of ALLETE common stock to our pension plan (0.2 million shares, which had an aggregate value of $13.5 million in 2017 and none in 2016). The shares of ALLETE common stock contributed in 2017 were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended.

Earnings Per Share. We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units and performance share awards granted under our Executive Long-Term Incentive Compensation Plan. No options to purchase shares of common stock were excluded from the computation of diluted earnings per share in 2018, 2017 and 2016.

NOTE 12. COMMON STOCK AND EARNINGS PER SHARE (Continued)

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2018			
Net Income Attributable to ALLETE	$174.1		$174.1
Average Common Shares	51.3	0.2	51.5
Earnings Per Share	$3.39		$3.38
Dividends Per Share	$2.24		$2.24
2017			
Net Income Attributable to ALLETE	$172.2		$172.2
Average Common Shares	50.8	0.2	51.0
Earnings Per Share	$3.39		$3.38
Dividends Per Share	$2.14		$2.14
2016			
Net Income Attributable to ALLETE	$155.3		$155.3
Average Common Shares	49.3	0.2	49.5
Earnings Per Share	$3.15		$3.14
Dividends Per Share	$2.08		$2.08

NOTE 13. INCOME TAX EXPENSE

Income Tax Expense **Year Ended December 31**	**2018**	**2017**	**2016**
Millions			
Current Income Tax Expense *(a)*			
Federal	—	—	—
State	$0.3	$0.3	$0.4
Total Current Income Tax Expense	$0.3	$0.3	$0.4
Deferred Income Tax Expense (Benefit)			
Federal *(b)*	$(26.2)	$12.1	$12.0
Federal – Remeasurement of Deferred Income Taxes *(c)*	—	(13.0)	—
State	11.0	15.8	8.1
Investment Tax Credit Amortization	(0.6)	(0.5)	(0.7)
Total Deferred Income Tax Expense (Benefit)	$(15.8)	$14.4	$19.4
Total Income Tax Expense (Benefit)	$(15.5)	$14.7	$19.8

(a) For the years ended December 31, 2018, 2017 and 2016, the federal and state current tax expense was minimal due to NOLs which resulted from the bonus depreciation provisions of the Protecting Americans from Tax Hikes Act of 2015, the Tax Increase Prevention Act of 2014 and the American Taxpayer Relief Act of 2012. Federal and state NOLs are being carried forward to offset current and future taxable income.

(b) For the year ended December 31, 2018, the federal tax benefit is primarily due to production tax credits, and the reduction of the federal statutory tax rate from 35 percent to 21 percent enacted as part of the TCJA.

(c) For the year ended December 31, 2017, the federal deferred income tax benefit is due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA.

Reconciliation of Taxes from Federal Statutory **Rate to Total Income Tax Expense** **Year Ended December 31**	**2018**	**2017**	**2016**
Millions			
Income Before Non-Controlling Interest and Income Taxes	$158.6	$186.9	$175.6
Statutory Federal Income Tax Rate	21%	35%	35%
Income Taxes Computed at Statutory Federal Rate	$33.3	$65.4	$61.5
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	8.9	10.5	5.6
Production Tax Credits	(45.0)	(45.1)	(41.5)
Regulatory Differences – Excess Deferred Tax Benefit *(a)*	(8.2)	1.2	1.4
Change in Fair Value of Contingent Consideration	(0.4)	—	(3.8)
Remeasurement of Deferred Income Taxes *(b)*	—	(13.0)	—
Other	(4.1)	(4.3)	(3.4)
Total Income Tax Expense (Benefit)	$(15.5)	$14.7	$19.8

(a) Excess deferred income taxes are being returned to customers under both the Average Rate Assumption Method and amortization periods as approved by regulators. (See Note 4. Regulatory Matters.)

(b) Deferred income tax benefit from the remeasurement of deferred income tax assets and liabilities resulting from the TCJA.

NOTE 13. INCOME TAX EXPENSE (Continued).

The effective tax rate was a benefit of 9.8 percent for 2018 (expense of 7.9 percent for 2017; expense of 11.3 percent for 2016). The 2018 effective tax rate was primarily impacted by production tax credits, and the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA. The 2017 effective tax rate was primarily impacted by production tax credits and the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. The 2016 effective tax rate was primarily impacted by production tax credits.

Deferred Income Tax Assets and Liabilities

As of December 31	**2018**	**2017**
Millions		
Deferred Income Tax Assets		
Employee Benefits and Compensation	$62.2	$65.9
Property-Related	95.2	104.3
NOL Carryforwards	86.1	99.1
Tax Credit Carryforwards	349.8	294.3
Power Sales Agreements	27.5	35.0
Regulatory Liabilities	113.4	117.7
Other	25.1	33.3
Gross Deferred Income Tax Assets	759.3	749.6
Deferred Income Tax Asset Valuation Allowance	(66.5)	(60.0)
Total Deferred Income Tax Assets	$692.8	$689.6
Deferred Income Tax Liabilities		
Property-Related	$752.5	$758.3
Regulatory Asset for Benefit Obligations	61.0	61.4
Unamortized Investment Tax Credits	32.2	32.8
Partnership Basis Differences	40.8	34.9
Regulatory Assets	29.9	32.0
Other	—	0.7
Total Deferred Income Tax Liabilities	$916.4	$920.1
Net Deferred Income Taxes *(a)*	$223.6	$230.5

(a) Recorded as a net long-term Deferred Income Tax liability on the Consolidated Balance Sheet

NOL and Tax Credit Carryforwards

As of December 31	**2018**	**2017**
Millions		
Federal NOL Carryforwards *(a)*	$319.0	$375.2
Federal Tax Credit Carryforwards	$256.4	$209.2
State NOL Carryforwards *(a)*	$305.8	$289.9
State Tax Credit Carryforwards *(b)*	$27.4	$25.6

(a) Pre-tax amounts.
(b) Net of a $66.0 million valuation allowance as of December 31, 2018 ($59.5 million as of December 31, 2017).

NOTE 13. INCOME TAX EXPENSE (Continued).

The federal NOL and tax credit carryforward periods expire between 2031 and 2038. We expect to fully utilize the federal NOL and federal tax credit carryforwards; therefore, no federal valuation allowance has been recognized as of December 31, 2018. The state NOL and tax credit carryforward periods expire between 2024 and 2045. We have established a valuation allowance against certain state NOL and tax credits that we do not expect to utilize before their expiration. We do not expect a material impact on the Company's ability to utilize its federal and state NOL and tax credit carryforwards due to the TCJA.

Gross Unrecognized Income Tax Benefits	**2018**	**2017**	**2016**
Millions			
Balance at January 1	$1.7	$2.0	$2.4
Additions for Tax Positions Related to the Current Year	0.1	0.1	0.1
Additions for Tax Positions Related to Prior Years	0.1	0.1	0.2
Reductions for Tax Positions Related to Prior Years	(0.2)	(0.1)	(0.3)
Lapse of Statute	(0.1)	(0.4)	(0.4)
Balance as of December 31	$1.6	$1.7	$2.0

Unrecognized tax benefits are the differences between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to the "more-likely-than-not" criteria. The unrecognized tax benefit balance includes permanent tax positions which, if recognized would affect the annual effective income tax rate. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The gross unrecognized tax benefits as of December 31, 2018, included $0.9 million of net unrecognized tax benefits which, if recognized, would affect the annual effective income tax rate.

As of December 31, 2018, we had no accrued interest (none as of December 31, 2017, and 2016) related to unrecognized tax benefits included on the Consolidated Balance Sheet due to our NOL carryforwards. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses on the Consolidated Statement of Income. Interest expense related to unrecognized tax benefits on the Consolidated Statement of Income was immaterial in 2018 (immaterial in 2017, and in 2016). There were no penalties recognized in 2018, 2017 or 2016. The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on the Consolidated Balance Sheet.

No material changes to unrecognized tax benefits are expected during the next 12 months.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE has no open federal or state audits, and is no longer subject to federal examination for years before 2015 or state examination for years before 2014.

NOTE 14. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in Accumulated Other Comprehensive Loss. Comprehensive income (loss) is the change in shareholders' equity during a period from transactions and events from non-owner sources, including net income. The amounts recorded to accumulated other comprehensive loss include unrealized gains and losses on available-for-sale debt securities as well as defined benefit pension and other postretirement items, consisting of deferred actuarial gains or losses and prior service costs or credits.

For the years ended December 31, 2018, 2017 and 2016, reclassifications out of accumulated other comprehensive loss for the company were not material. Changes in accumulated other comprehensive loss are presented on the Consolidated Statement of Shareholders' Equity.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

We have noncontributory union, non-union and combined retiree defined benefit pension plans covering eligible employees. The combined retiree defined benefit pension plan was created in 2016, to include all union and non-union retirees from the existing plans as of January 1, 2016. The plans provide defined benefits based on years of service and final average pay. We contributed $15.0 million in cash to the plans in 2018 ($1.7 million in 2017; $6.3 million in 2016). We contributed no shares of ALLETE common stock to the plans in 2018 (0.2 million shares, which had an aggregate value of $13.5 million in 2017; none in 2016). We also have a defined contribution RSOP covering substantially all employees. The 2018 plan year employer contributions, which are made through the employee stock ownership plan portion of the RSOP, totaled $11.4 million ($11.0 million for the 2017 plan year; $9.2 million for the 2016 plan year). (See Note 12. Common Stock and Earnings Per Share and Note 16. Employee Stock and Incentive Plans.)

The non-union defined benefit pension plan was frozen in 2018, and does not allow further crediting of service or earnings to the plan. Further, it is closed to new participants. The Minnesota Power union defined benefit pension plan is also closed to new participants.

We have postretirement health care and life insurance plans covering eligible employees. In 2010, the postretirement health care plan was closed to employees hired after January 31, 2011, and the eligibility requirements were amended. In 2014, the postretirement life plan was amended to close the plan to non-union employees retiring after December 31, 2015, and in 2018, the postretirement life plan was amended to limit the benefit level for union employees retiring after December 31, 2018. The postretirement health and life plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and irrevocable grantor trusts. In 2018, no contributions were made to the VEBAs (none in 2017; none in 2016) and no contributions were made to the grantor trusts (none in 2017; none in 2016).

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the pension plans. Contributions are based on estimates and assumptions which are subject to change. On January 15, 2019, we contributed $10.4 million in cash to the defined benefit pension plans. We do not expect to make any additional contributions to the defined benefit pension plans in 2019, and we do not expect to make any contributions to the defined benefit postretirement health and life plans in 2019.

Accounting for defined benefit pension and other postretirement benefit plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

The defined benefit pension and postretirement health and life benefit expense (credit) recognized annually by our regulated utilities are expected to be recovered (refunded) through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset (regulatory liability) on the Consolidated Balance Sheet, in accordance with the accounting standards for the effect of certain types of regulation applicable to our Regulated Operations. The defined benefit pension and postretirement health and life benefit expense (credits) associated with our other operations are recognized in accumulated other comprehensive income.

Pension Obligation and Funded Status

As of December 31	**2018**	**2017**
Millions		
Accumulated Benefit Obligation	$713.7	$745.4
Change in Benefit Obligation		
Obligation, Beginning of Year	$793.2	$743.3
Service Cost	11.0	10.2
Interest Cost	29.6	32.5
Plan Amendments	(1.5)	—
Plan Curtailments	(6.9)	—
Actuarial (Gain) Loss	(53.0)	44.8
Benefits Paid	(49.5)	(51.0)
Participant Contributions	24.1	13.4
Obligation, End of Year	$747.0	$793.2
Change in Plan Assets		
Fair Value, Beginning of Year	$628.2	$557.5
Actual Return on Plan Assets	(21.2)	91.6
Employer Contribution *(a)*	40.5	30.1
Benefits Paid	(49.5)	(51.0)
Fair Value, End of Year	$598.0	$628.2
Funded Status, End of Year	$(149.0)	$(165.0)

Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(1.6)	$(1.4)
Non-Current Liabilities	$(147.4)	$(163.6)

(a) Includes Participant Contributions noted above.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

The pension costs that are reported as a component within the Consolidated Balance Sheet, reflected in long-term regulatory assets or liabilities and accumulated other comprehensive income, consist of a net loss of $230.5 million and prior service cost of $1.4 million as of December 31, 2018 (net loss of $236.2 million as of December 31, 2017).

Reconciliation of Net Pension Amounts Recognized in Consolidated Balance Sheet

As of December 31	2018	2017
Millions		
Net Loss	$(230.5)	$(236.2)
Prior Service Cost	1.4	—
Accumulated Contributions in Excess of Net Periodic Benefit Cost (Prepaid Pension Asset)	80.1	71.2
Total Net Pension Amounts Recognized in Consolidated Balance Sheet	$(149.0)	$(165.0)

Components of Net Periodic Pension Cost

Year Ended December 31	2018	2017	2016
Millions			
Service Cost	$11.0	$10.2	$8.1
Non-Service Cost Components *(a)*			
Interest Cost	29.6	32.5	33.2
Expected Return on Plan Assets	(44.4)	(42.4)	(43.6)
Amortization of Loss	11.4	9.9	9.5
Amortization of Prior Service Cost	(0.1)	—	—
Net Pension Cost	$7.5	$10.2	$7.2

(a) These components of net periodic pension cost are included in the line item "Other" under Other Income (Expense) on the Consolidated Statement of Income.

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities

Year Ended December 31	2018	2017
Millions		
Net (Gain) Loss	$5.8	$(4.3)
Amortization of Prior Service Cost	0.1	—
Prior Service Cost Arising During the Period	(1.6)	—
Amortization of Loss	(11.4)	(9.9)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$(7.1)	$(14.2)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

As of December 31	**2018**	**2017**
Millions		
Projected Benefit Obligation	$747.0	$793.2
Accumulated Benefit Obligation	$713.7	$745.4
Fair Value of Plan Assets	$598.0	$628.2

Postretirement Health and Life Obligation and Funded Status

As of December 31	**2018**	**2017**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$190.1	$173.4
Service Cost	4.7	4.4
Interest Cost	7.1	7.7
Actuarial (Gain) Loss	(15.8)	15.5
Benefits Paid	(11.6)	(12.2)
Participant Contributions	3.6	3.1
Plan Amendments	(2.1)	(1.8)
Obligation, End of Year	$176.0	$190.1
Change in Plan Assets		
Fair Value, Beginning of Year	$171.0	$154.3
Actual Return on Plan Assets	(9.6)	24.5
Employer Contribution	1.0	1.3
Participant Contributions	3.6	3.1
Benefits Paid	(11.7)	(12.2)
Fair Value, End of Year	$154.3	$171.0
Funded Status, End of Year	$(21.7)	$(19.1)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:

Non-Current Assets	$0.4	$3.0
Current Liabilities	$(1.0)	$(1.1)
Non-Current Liabilities	$(21.1)	$(21.0)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

According to the accounting standards for retirement benefits, only assets in the VEBAs are treated as plan assets in the preceding table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $18.3 million in irrevocable grantor trusts included in Other Investments on the Consolidated Balance Sheet as of December 31, 2018 ($19.2 million as of December 31, 2017).

The postretirement health and life costs that are reported as a component within the Consolidated Balance Sheet, reflected in regulatory long-term assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs

As of December 31	2018	2017
Millions		
Net Loss	$25.0	$21.1
Prior Service Credit	(4.6)	(4.6)
Total Unrecognized Postretirement Health and Life Cost	$20.4	$16.5

Reconciliation of Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet

As of December 31	2018	2017
Millions		
Net Loss *(a)*	$(25.0)	$(21.1)
Prior Service Credit	4.6	4.6
Accumulated Net Periodic Benefit Cost in Excess of Contributions *(a)*	(1.3)	(2.6)
Total Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet	$(21.7)	$(19.1)

(a) Excludes gains, losses and contributions associated with irrevocable grantor trusts.

Components of Net Periodic Postretirement Health and Life Cost

Year Ended December 31	2018	2017	2016
Millions			
Service Cost	$4.7	$4.4	$3.9
Non-Service Cost Components *(a)*			
Interest Cost	7.1	7.7	7.4
Expected Return on Plan Assets	(10.9)	(10.5)	(11.2)
Amortization of Loss	0.8	0.3	0.2
Amortization of Prior Service Credit	(2.1)	(2.0)	(2.9)
Net Postretirement Health and Life Credit	$(0.4)	$(0.1)	$(2.6)

(a) These components of net periodic postretirement health and life cost are included in the line item "Other" under Other Income (Expense) on the Consolidated Statement of Income.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities

Year Ended December 31	2018	2017
Millions		
Net Loss	$4.7	$1.6
Prior Service Credit Arising During the Period	(2.1)	(1.8)
Amortization of Prior Service Credit	2.1	2.0
Amortization of Loss	(0.8)	(0.3)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$3.9	$1.5

Estimated Future Benefit Payments	Pension	Postretirement Health and Life
Millions		
2019	$47.9	$9.7
2020	$47.4	$9.7
2021	$47.3	$9.8
2022	$47.1	$9.8
2023	$47.0	$9.7
Years 2024 – 2028	$231.1	$51.1

The pension and postretirement health and life costs recorded in regulatory long-term assets or liabilities and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2019, are as follows:

	Pension	Postretirement Health and Life
Millions		
Net Loss	$7.3	$0.4
Prior Service Credit	(0.2)	(1.7)
Total Pension and Postretirement Health and Life Cost (Credit)	$7.1	$(1.3)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Assumptions Used to Determine Benefit Obligation

As of December 31	2018	2017
Discount Rate		
Pension	4.39 - 4.53%	3.81 - 3.96%
Postretirement Health and Life	4.47%	3.86%
Rate of Compensation Increase	3.70 - 4.10%	3.70 - 4.10%
Health Care Trend Rates		
Trend Rate	5.00 - 6.46%	5.00 - 6.73%
Ultimate Trend Rate	4.50%	4.50%
Year Ultimate Trend Rate Effective	2038	2038

Assumptions Used to Determine Net Periodic Benefit Costs

Year Ended December 31	2018	2017	2016
Discount Rate	3.81 - 3.96%	4.53 - 4.57%	4.72 - 4.73%
Expected Long-Term Return on Plan Assets			
Pension	7.50%	7.50%	8.00%
Postretirement Health and Life	6.00 - 7.50%	6.00 - 7.50%	6.40 - 8.00%
Rate of Compensation Increase	3.70 - 4.10%	3.70 - 4.30%	3.70 - 4.30%

In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions, and utilizing the target allocation of our plan assets, forecast the expected long-term rate of return.

The discount rate is computed using a bond matching study which utilizes a portfolio of high quality bonds that produce cash flows similar to the projected costs of our pension and other postretirement plans.

The Company utilizes actuarial assumptions about mortality to calculate the pension and postretirement health and life benefit obligations. The mortality assumptions used to calculate our pension and other postretirement benefit obligations as of December 31, 2018, considered a modified RP-2014 mortality table and mortality projection scale.

Sensitivity of a One Percent Change in Health Care Trend Rates

	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$2.0	$(1.6)
Effect on Postretirement Health and Life Obligation	$20.7	$(17.2)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Actual Plan Asset Allocations	Pension		Postretirement Health and Life *(a)*	
	2018	2017	2018	2017
Equity Securities	32 %	53 %	62 %	64 %
Fixed Income Securities	60 %	38 %	34 %	31 %
Private Equity	5 %	5 %	4 %	5 %
Real Estate	3 %	4 %	—	—
	100 %	100 %	100 %	100 %

(a) Includes VEBAs and irrevocable grantor trusts.

There were no shares of ALLETE common stock included in pension plan equity securities as of December 31, 2018 (no shares as of December 31, 2017).

The defined benefit pension plans have adopted a dynamic asset allocation strategy (glide path) that increases the invested allocation to fixed income assets as the funding level of the plan increases to better match the sensitivity of the plan's assets and liabilities to changes in interest rates. This is expected to reduce the volatility of reported pension plan expenses. The postretirement health and life plans' assets are diversified to achieve strong returns within managed risk. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds.

Following are the current targeted allocations as of December 31, 2018:

Plan Asset Target Allocations	Pension	Postretirement Health and Life *(a)*
Equity Securities	32 %	60 %
Fixed Income Securities	56 %	37 %
Private Equity	6 %	3 %
Real Estate	6 %	—
	100 %	100 %

(a) Includes VEBAs and irrevocable grantor trusts.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). (See Note 9. Fair Value)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Pension Fair Value

	Fair Value as of December 31, 2018			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	—	$59.1	—	$59.1
U.S. Mid-cap Growth *(a)*	—	28.1	—	28.1
U.S. Small-cap *(a)*	—	27.2	—	27.2
International	—	75.8	—	75.8
Fixed Income Securities	—	352.9	—	352.9
Cash and Cash Equivalents	$6.3	—	—	6.3
Private Equity Funds	—	—	$27.8	27.8
Real Estate	—	—	20.8	20.8
Total Fair Value of Assets	$6.3	$543.1	$48.6	$598.0

(a) The underlying investments consist of actively-managed funds managed to achieve the returns of certain U.S. equity securities large-cap, mid-cap and small-cap indexes.

Recurring Fair Value Measures

Activity in Level 3	**Private Equity Funds**	**Real Estate**
Millions		
Balance as of December 31, 2017	$33.2	$25.5
Actual Return on Plan Assets	2.8	0.7
Purchases, Sales, and Settlements – Net	(8.2)	(5.4)
Balance as of December 31, 2018	$27.8	$20.8

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Fair Value (Continued)

	Fair Value as of December 31, 2017			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	—	$108.6	—	$108.6
U.S. Mid-cap Growth *(a)*	—	51.9	—	51.9
U.S. Small-cap *(a)*	—	51.5	—	51.5
International	—	122.3	—	122.3
Fixed Income Securities	—	222.8	—	222.8
Cash and Cash Equivalents	$12.4	—	—	12.4
Private Equity Funds	—	—	$33.2	33.2
Real Estate	—	—	25.5	25.5
Total Fair Value of Assets	$12.4	$557.1	$58.7	$628.2

(a) The underlying investments consist of actively-managed funds managed to achieve the returns of certain U.S. equity securities large-cap, mid-cap and small-cap indexes.

Recurring Fair Value Measures

Activity in Level 3	**Private Equity Funds**	**Real Estate**
Millions		
Balance as of December 31, 2016	$40.6	$25.6
Actual Return on Plan Assets	7.1	1.7
Purchases, Sales, and Settlements – Net	(14.5)	(1.8)
Balance as of December 31, 2017	$33.2	$25.5

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

Postretirement Health and Life Fair Value

	Fair Value as of December 31, 2018			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities: *(a)*				
U.S. Large-cap	$29.1	—	—	$29.1
U.S. Mid-cap Growth	21.2	—	—	21.2
U.S. Small-cap	12.9	—	—	12.9
International	30.4	—	—	30.4
Fixed Income Securities:				
Mutual Funds	49.6	—	—	49.6
Debt Securities	—	$4.0	—	4.0
Cash and Cash Equivalents	0.6	—	—	0.6
Private Equity Funds	—	—	$6.5	6.5
Total Fair Value of Assets	$143.8	$4.0	$6.5	$154.3

(a) The underlying investments consist of mutual funds (Level 1).

Recurring Fair Value Measures

Activity in Level 3	**Private Equity Funds**
Millions	
Balance as of December 31, 2017	$8.2
Actual Return on Plan Assets	0.9
Purchases, Sales, and Settlements – Net	(2.6)
Balance as of December 31, 2018	$6.5

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

	Fair Value as of December 31, 2017			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities: *(a)*				
U.S. Large-cap	$32.1	—	—	$32.1
U.S. Mid-cap Growth	24.3	—	—	24.3
U.S. Small-cap	15.5	—	—	15.5
International	35.8	—	—	35.8
Fixed Income Securities:				
Mutual Funds	49.8	—	—	49.8
Debt Securities	—	$4.5	—	4.5
Cash and Cash Equivalents	0.8	—	—	0.8
Private Equity Funds	—	—	$8.2	8.2
Total Fair Value of Assets	$158.3	$4.5	$8.2	$171.0

(a) The underlying investments consist of mutual funds (Level 1).

Recurring Fair Value Measures **Activity in Level 3**	**Private Equity Funds**
Millions	
Balance as of December 31, 2016	$9.5
Actual Return on Plan Assets	2.6
Purchases, Sales, and Settlements – Net	(3.9)
Balance as of December 31, 2017	$8.2

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide a fully insured postretirement health benefit, including a prescription drug benefit, which qualifies us for a federal subsidy under the Act. The federal subsidy is reflected in the premiums charged to us by the insurance company.

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS

Employee Stock Ownership Plan. We sponsor an ESOP within the RSOP. Eligible employees may contribute to the RSOP plan as of their date of hire. The dividends received by the ESOP are distributed to participants. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings. ESOP employer allocations are funded with contributions paid in either cash or the issuance of ALLETE common stock at the Company's discretion. We record compensation expense equal to the cash or current market price of stock contributed. ESOP compensation expense was $11.4 million in 2018 ($11.0 million in 2017; $9.2 million in 2016).

According to the accounting standards for stock compensation, unallocated shares of ALLETE common stock held and purchased by the ESOP were treated as unearned ESOP shares and not considered outstanding for earnings per share computations. All ESOP shares have been allocated to participants as of December 31, 2018, 2017 and 2016.

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, restricted stock units, stock appreciation rights and other awards. There are 0.9 million shares of ALLETE common stock reserved for issuance under the Executive Plan, of which 0.7 million of these shares remain available for issuance as of December 31, 2018.

The following types of share-based awards were outstanding in 2018, 2017 or 2016:

Non-Qualified Stock Options. Stock options have not been granted since 2008 and none were outstanding as of December 31, 2018 (none in 2017 and an immaterial amount in 2016). These options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to 3 months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are canceled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is eligible for retirement.

The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the grant date. Expected volatility is estimated based on the historic volatility of our stock and the stock of our peer group companies. We utilize historical option exercise and employee pre-vesting termination data to estimate the option life. The dividend growth rate is based upon historical growth rates in our dividends.

Performance Shares. Under the performance share awards, the number of shares earned is contingent upon attaining specific market goals over a three-year performance period. Market goals are measured by total shareholder return relative to a group of peer companies. In the case of qualified retirement, death, or disability during a performance period, a pro rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death, or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is determined by the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)
Stock-Based Compensation (Continued)

Restricted Stock Units. Under the restricted stock unit awards, shares for participants eligible for retirement vest monthly over a three-year period. For participants not eligible for retirement, shares vest at the end of the three-year period. In the case of qualified retirement, death or disability, a pro rata portion of the award will be earned. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be earned. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price; we are not required to apply fair value accounting to these awards as the discount is not greater than 5 percent.

RSOP. The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our Consolidated Statement of Income for the periods presented.

Share-Based Compensation Expense

Year Ended December 31	**2018**	**2017**	**2016**
Millions			
Performance Shares	$2.3	$2.1	$1.8
Restricted Stock Units	0.9	1.0	0.8
Total Share-Based Compensation Expense	$3.2	$3.1	$2.6
Income Tax Benefit	$0.9	$0.9	$1.1

There were no capitalized share-based compensation costs during the years ended December 31, 2018, 2017 or 2016.

As of December 31, 2018, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our Consolidated Statement of Income was $3.0 million and $1.0 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years and 1.6 years respectively.

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)
Stock-Based Compensation (Continued)

Performance Shares. The following table presents information regarding our non-vested performance shares.

	2018		2017		2016	
	Number of	Weighted-Average Grant Date Fair Value	Number of	Weighted-Average Grant Date Fair Value	Number of	Weighted-Average Grant Date Fair Value
Non-vested as of January 1	127,898	$58.23	127,580	$52.56	119,540	$52.72
Granted *(a)*	66,557	$76.42	50,729	$62.90	57,189	$52.43
Awarded	(58,293)	$59.82	—	—	—	—
Unearned Grant Award	—	—	(40,801)	$46.27	(42,126)	$52.70
Forfeited	(6,469)	$72.99	(9,610)	$58.29	(7,023)	$53.45
Non-vested as of December 31	129,693	$66.12	127,898	$58.23	127,580	$52.56

(a) Shares granted include accrued dividends.

There were 31,843 performance shares granted in January 2019 for the three-year performance period ending in 2021. The ultimate issuance is contingent upon the attainment of certain goals of ALLETE during the performance periods. The grant date fair value of the performance shares granted was $2.3 million. There were 73,532 performance shares awarded in February 2019. The grant date fair value of the shares awarded was $3.9 million.

Restricted Stock Units. The following table presents information regarding our available restricted stock units.

	2018		2017		2016	
	Number of	Weighted-Average Grant Date Fair Value	Number of	Weighted-Average Grant Date Fair Value	Number of	Weighted-Average Grant Date Fair Value
Available as of January 1	55,248	$56.18	54,728	$51.79	57,694	$49.86
Granted *(a)*	16,573	$71.11	21,241	$62.20	20,351	$50.25
Awarded	(18,881)	$55.78	(17,281)	$49.72	(19,661)	$44.33
Forfeited	(3,169)	$64.92	(3,440)	$56.00	(3,656)	$52.87
Available as of December 31	49,771	$60.74	55,248	$56.18	54,728	$51.79

(a) Shares granted include accrued dividends.

There were 12,924 restricted stock units granted in January 2019 for the vesting period ending in 2021. The grant date fair value of the restricted stock units granted was $1.0 million. There were 14,307 restricted stock units awarded in February 2019. The grant date fair value of the shares awarded was $0.7 million.

NOTE 17. BUSINESS SEGMENTS

We present three reportable segments: Regulated Operations, ALLETE Clean Energy, and U.S. Water Services. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes three operating segments which consist of our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC. ALLETE Clean Energy is our business focused on developing, acquiring and operating clean and renewable energy projects. U.S. Water Services is our integrated water management company. The ALLETE Clean Energy and U.S. Water Services reportable segments comprise our Energy Infrastructure and Related Services businesses. We also present Corporate and Other which includes two operating segments, BNI Energy, our coal mining operations in North Dakota, and ALLETE Properties, our legacy Florida real estate investment, along with our investment in Nobles 2, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 4,000 acres of land in Minnesota, and earnings on cash and investments.

NOTE 17. BUSINESS SEGMENTS (Continued)

Year Ended December 31	2018	2017	2016
Millions			
Operating Revenue *(a)*			
Residential	$139.7	$127.4	$127.9
Commercial	147.9	139.8	139.5
Municipal	54.9	57.9	67.6
Industrial	469.5	470.5	416.0
Other Power Suppliers	170.3	161.8	175.1
CIP Financial Incentive	3.0	5.5	7.5
Other	74.2	100.9	67.1
Total Regulated Operations	1,059.5	1,063.8	1,000.7
Energy Infrastructure and Related Services			
ALLETE Clean Energy			
Long-term PSA	55.2	56.9	58.2
Sale of Wind Energy Facility	81.1	—	—
Other	23.6	23.6	22.3
Total ALLETE Clean Energy	159.9	80.5	80.5
U.S. Water Services			
Point-in-time	100.3	95.8	93.9
Contract	38.3	36.2	30.4
Capital Project	33.5	19.8	13.2
Total U.S. Water Services	172.1	151.8	137.5
Corporate and Other			
Long-term Contract	85.5	89.3	73.7
Other	21.6	33.9	47.3
Total Corporate and Other	107.1	123.2	121.0
Total Operating Revenue	$1,498.6	$1,419.3	$1,339.7
Net Income (Loss) Attributable to ALLETE *(b)(c)*			
Regulated Operations	$131.0	$128.4	$135.5
Energy Infrastructure and Related Services			
ALLETE Clean Energy *(d)*	33.7	41.5	13.4
U.S. Water Services	3.2	10.7	1.5
Corporate and Other *(e)*	6.2	(8.4)	4.9
Total Net Income Attributable to ALLETE	$174.1	$172.2	$155.3

NOTE 17. BUSINESS SEGMENTS (Continued)

(a) With the adoption of new revenue recognition guidance, the Company has enhanced the presentation of business segment Operating Revenue. (See Note 1. Operations and Significant Accounting Policies.)

(b) Net income in 2017 included a favorable impact of $13.0 million after-tax due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, which consisted of a $23.6 million after-tax benefit for ALLETE Clean Energy, a $9.2 million after-tax benefit for U.S. Water Services and a $19.8 million after-tax expense for Corporate and Other. The TCJA did not have an impact on net income for our Regulated Operations as the remeasurement of deferred income tax assets and liabilities primarily resulted in the recording of regulatory assets and liabilities. (See Note 1. Operations and Significant Accounting Policies and Note 4. Regulatory Matters.)

(c) Includes interest expense resulting from intercompany loan agreements and allocated to certain subsidiaries. The amounts are eliminated in consolidation.

(d) Net income in 2018 includes the recognition of profit for the sale of a wind energy facility to Montana-Dakota Utilities.

(e) Net income in 2017 included a $7.9 million after-tax favorable impact for the regulatory outcome of the MPUC's modification of tits November 2016 order on the allocation of North Dakota investment tax credits. Net income in 2016 included an $8.8 million after-tax adverse impact for the regulatory outcome of the November 2016 order.

NOTE 17. BUSINESS SEGMENTS (Continued)

Year Ended December 31	2018	2017	2016
Millions			
Depreciation and Amortization			
Regulated Operations	$158.0	$132.6	$154.3
Energy Infrastructure and Related Services			
ALLETE Clean Energy	24.4	23.4	22.3
U.S. Water Services	10.2	9.8	8.9
Corporate and Other	13.0	11.7	10.3
Total Depreciation and Amortization	$205.6	$177.5	$195.8
Operating Expenses – Other *(a)*			
ALLETE Clean Energy	—	—	$3.3
Corporate and Other	$(2.0)	$(0.7)	(13.6)
Total Operating Expenses – Other	$(2.0)	$(0.7)	$(10.3)
Interest Expense *(b)*			
Regulated Operations	$60.2	$57.0	$52.1
Energy Infrastructure and Related Services			
ALLETE Clean Energy	3.6	4.2	5.8
U.S. Water Services	1.5	1.6	1.7
Corporate and Other	7.3	10.3	14.5
Eliminations	(4.7)	(5.3)	(3.8)
Total Interest Expense	$67.9	$67.8	$70.3
Equity Earnings in ATC			
Regulated Operations	$17.5	$22.5	$18.5
Income Tax Expense (Benefit) *(c)*			
Regulated Operations *(d)*	$(15.5)	$27.2	$5.9
Energy Infrastructure and Related Services			
ALLETE Clean Energy	(1.0)	(14.2)	8.1
U.S. Water Services	1.0	(7.8)	1.4
Corporate and Other *(d)*	—	9.5	4.4
Total Income Tax Expense (Benefit)	$(15.5)	$14.7	$19.8

NOTE 17. BUSINESS SEGMENTS (Continued)

(a) See Note 1. Operations and Significant Accounting Policies.

(b) Includes interest expense resulting from intercompany loan agreements and allocated to certain subsidiaries. The amounts are eliminated in consolidation.

(c) Income tax expense in 2017 included an income tax benefit of $13.0 million due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, which consisted of income tax benefits of $23.6 million for ALLETE Clean Energy and $9.2 million for U.S. Water Services as well as additional income tax expense of $19.8 million for Corporate and Other. The TCJA did not have an impact on income tax expense for our Regulated Operations as the remeasurement of deferred income tax assets and liabilities primarily resulted in the recording of regulatory assets and liabilities. (See Note 1. Operations and Significant Accounting Policies and Note 4. Regulatory Matters.)

(d) In 2017, Regulated Operations includes $14.0 million of income tax expense related to North Dakota investment tax credits transferred to Corporate and Other and higher pre-tax income for the favorable impact for the regulatory outcome of the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits. There was no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax benefit of $7.9 million in 2017. In 2016, Regulated Operations includes $15.0 million of income tax benefit for North Dakota investment tax credits transferred from Corporate and Other and lower pre-tax income related to the adverse impact for the regulatory outcome of the November 2016 MPUC order. There was no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax expense of $8.8 million in 2016. (See Note 4. Regulatory Matters.)

NOTE 17. BUSINESS SEGMENTS (Continued)

As of December 31	**2018**	**2017**
Millions		
Assets		
Regulated Operations	$3,952.5	$3,886.6
Energy Infrastructure and Related Services		
ALLETE Clean Energy	606.6	600.5
U.S. Water Services	295.8	292.4
Corporate and Other	310.1	300.5
Total Assets	$5,165.0	$5,080.0
Capital Expenditures		
Regulated Operations	$211.9	$177.1
Energy Infrastructure and Related Services		
ALLETE Clean Energy	89.7	56.1
U.S. Water Services	5.0	4.4
Corporate and Other	12.0	28.9
Total Capital Expenditures	$318.6	$266.5

NOTE 18. QUARTERLY FINANCIAL DATA (UNAUDITED)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	**Mar. 31**	**Jun. 30**	**Sept. 30**	**Dec. 31**
Millions Except Earnings Per Share				
2018				
Operating Revenue	$358.2	$344.1	$348.0	$448.3
Operating Income	$57.4	$36.5	$43.3	$64.0
Net Income Attributable to ALLETE	$51.0	$31.3	$30.7	$61.1
Earnings Per Share of Common Stock				
Basic	$1.00	$0.61	$0.59	$1.19
Diluted	$0.99	$0.61	$0.59	$1.18
2017				
Operating Revenue	$365.6	$353.3	$362.5	$337.9
Operating Income	$71.6	$54.0	$68.0	$32.3
Net Income Attributable to ALLETE	$49.0	$36.9	$44.9	$41.4
Earnings Per Share of Common Stock				
Basic	$0.97	$0.73	$0.88	$0.81
Diluted	$0.97	$0.72	$0.88	$0.81
2016				
Operating Revenue	$333.8	$314.8	$349.6	$341.5
Operating Income	$65.2	$40.6	$51.8	$59.4
Net Income Attributable to ALLETE	$45.9	$24.8	$40.3	$44.3
Earnings Per Share of Common Stock				
Basic	$0.93	$0.50	$0.82	$0.89
Diluted	$0.93	$0.50	$0.81	$0.89

NOTE 19. REGULATORY ACCOUNTING ISSUES

Basis of Accounting. The financial statements have been prepared in accordance with the accounting requirements of the uniform systems of accounts as prescribed by the FERC. The principle differences from generally accepted accounting principles include the exclusion of current maturities of long-term debt, the exclusion of preferred stock from current liabilities, the classification of deferred income taxes due to the guidance in accounting for income taxes, the classification of certain non-ARO plant removal obligations and the classification of certain securities investments due to the guidance for certain investments in debt and equity securities. As required by the FERC for this Form 1 report, ALLETE, Inc. accounts for its investments in majority owned subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by generally accepted accounting principles.

Definitions

The following abbreviations or acronyms are used in the text. References in this report to “we,” “us” and “our” are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc. and its subsidiaries
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ALLETE South Wind	ALLETE South Wind, LLC
ALLETE Transmission Holdings	ALLETE Transmission Holdings, Inc.
ArcelorMittal	ArcelorMittal USA, Inc.
ASC	Accounting Standards Codification
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison	Bison Wind Energy Center
BNI Energy	BNI Energy, Inc. and its subsidiary
Boswell	Boswell Energy Center
Camp Ripley	Camp Ripley Solar Array
CIP	Conservation Improvement Program
Cliffs	Cleveland-Cliffs Inc.
CO2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
DC	Direct Current
EIS	Environmental Impact Statement
EITE	Energy-Intensive Trade-Exposed
EPA	United States Environmental Protection Agency
ERP Iron Ore	ERP Iron Ore, LLC
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
IRP	Integrated Resource Plan
Item ___	Item ___ of this FERC Form 1

Definitions (Continued)

kV	Kilovolt(s)
kW / kWh	Kilowatt(s) / Kilowatt-hour(s)
Laskin	Laskin Energy Center
Magnetation	Magnetation, LLC
Manitoba Hydro	Manitoba Hydro-Electric Board
MBtu	Million British thermal units
Mesabi Metallics	Mesabi Metallics Company, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent System Operator, Inc.
Montana-Dakota Utilities	Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.
Moody’s	Moody’s Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
Nobles 2	Nobles 2 Power Partners, LLC
NOL	Net Operating Loss
NOX	Nitrogen Oxides
Northern States Power	Northern States Power Company, a subsidiary of Xcel Energy Inc.
Northshore Mining	Northshore Mining Company, a wholly-owned subsidiary of Cliffs
Note ___	Note ___ to the consolidated financial statements in this FERC Form 1
NTEC	Nemadji Trail Energy Center
NYSE	New York Stock Exchange
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park District	Palm Coast Park Community Development District in Florida
PolyMet	PolyMet Mining Corp.
PPA / PSA	Power Purchase Agreement / Power Sales Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
S&P Global Ratings	Standard and Poor’s Global Ratings
Shell Energy	Shell Energy North America (US), L.P.
Silver Bay Power	Silver Bay Power Company, a wholly-owned subsidiary of Cliffs
SO2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative, a North Dakota cooperative corporation
SWL&P	Superior Water, Light and Power Company

Definitions (Continued)

Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Tenaska	Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC
TCJA	Tax Cuts and Jobs Act of 2017 (Public Law 115-97)
Tonka Water	Tonka Equipment Company
Town Center District	Town Center at Palm Coast Community Development District in Florida
TransAlta	TransAlta Energy Marketing (U.S.) Inc.
United Taconite	United Taconite LLC, a wholly-owned subsidiary of Cliffs
UPM Blandin	UPM, Blandin paper mill owned by UPM-Kymmene Corporation
U.S.	United States of America
U.S. Water Services	U.S. Water Services, Inc. and its subsidiaries
USS Corporation	United States Steel Corporation
WTG	Wind Turbine Generator

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,258,202,634	4,258,202,634
4	Property Under Capital Leases	14,971,361	14,971,361
5	Plant Purchased or Sold		
6	Completed Construction not Classified	98,923,740	98,923,740
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,372,097,735	4,372,097,735
9	Leased to Others		
10	Held for Future Use	19,426	19,426
11	Construction Work in Progress	245,619,192	245,619,192
12	Acquisition Adjustments	968,840	968,840
13	Total Utility Plant (8 thru 12)	4,618,705,193	4,618,705,193
14	Accum Prov for Depr, Amort, & Depl	1,519,751,227	1,519,751,227
15	Net Utility Plant (13 less 14)	3,098,953,966	3,098,953,966
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,468,385,147	1,468,385,147
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	51,345,716	51,345,716
22	Total In Service (18 thru 21)	1,519,730,863	1,519,730,863
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	20,364	20,364
29	Amortization		
30	Total Held for Future Use (28 & 29)	20,364	20,364
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,519,751,227	1,519,751,227

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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					33

Schedule Page: 200   Line No.: 3   Column: c

Amount includes $44,888,959 Non-Regulated Plant in Service.

Schedule Page: 200   Line No.: 6   Column: c

Amount includes $360,989 Non-Regulated Completed Construction not Classified.

Schedule Page: 200   Line No.: 11   Column: c

Amount includes $135,989 Non-Regulated Construction Work in Progress.

Schedule Page: 200   Line No.: 14   Column: c

Amount includes $17,682,550 of Non-Regulated Accumulated Provision for Depreciation, Amortization & Depletion and $(186,550) of Non-Regulated Retirement Work in Progress.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	100,000	
3	(302) Franchises and Consents	4,677,060	
4	(303) Miscellaneous Intangible Plant	68,342,843	2,591,367
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	73,119,903	2,591,367
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	10,588,130	
9	(311) Structures and Improvements	198,159,813	1,590,495
10	(312) Boiler Plant Equipment	1,135,459,203	6,811,987
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	169,763,635	71,463
13	(315) Accessory Electric Equipment	157,652,542	-1,211,332
14	(316) Misc. Power Plant Equipment	10,989,581	26,874
15	(317) Asset Retirement Costs for Steam Production	29,639,264	20,762,490
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,712,252,168	28,051,977
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	3,705,454	
28	(331) Structures and Improvements	18,521,290	2,098,444
29	(332) Reservoirs, Dams, and Waterways	126,013,258	3,797,456
30	(333) Water Wheels, Turbines, and Generators	33,677,363	-55,513
31	(334) Accessory Electric Equipment	20,492,300	309,219
32	(335) Misc. Power PLant Equipment	1,809,097	
33	(336) Roads, Railroads, and Bridges	436,520	-250
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	204,655,282	6,149,356
36	D. Other Production Plant		
37	(340) Land and Land Rights	1,481,918	9
38	(341) Structures and Improvements	52,827,507	-168,167
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators	732,711,062	516,818
42	(345) Accessory Electric Equipment	49,658,099	209
43	(346) Misc. Power Plant Equipment	3,220,843	
44	(347) Asset Retirement Costs for Other Production	11,124,296	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	851,023,725	348,869
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,767,931,175	34,550,202

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	15,786,555	177,996
49	(352) Structures and Improvements	23,623,051	-2,744,047
50	(353) Station Equipment	320,620,922	1,982,137
51	(354) Towers and Fixtures	26,033,935	22,923
52	(355) Poles and Fixtures	267,542,316	7,132,341
53	(356) Overhead Conductors and Devices	118,756,061	2,926,019
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	2,988,455	
56	(359) Roads and Trails	58,614	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	775,409,909	9,497,369
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,627,588	662,920
61	(361) Structures and Improvements	9,458,134	2,235,549
62	(362) Station Equipment	82,322,810	10,909,705
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	110,969,134	5,029,581
65	(365) Overhead Conductors and Devices	93,304,673	2,515,928
66	(366) Underground Conduit	12,315,934	806
67	(367) Underground Conductors and Devices	99,506,297	4,073,526
68	(368) Line Transformers	90,973,212	2,563,745
69	(369) Services	18,236,249	344,906
70	(370) Meters	60,111,501	6,790,573
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises	2,061,798	99,476
73	(373) Street Lighting and Signal Systems	4,097,338	413,043
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	586,984,668	35,639,758
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,908,463	393,749
87	(390) Structures and Improvements	79,529,172	648,844
88	(391) Office Furniture and Equipment	24,122,452	2,170,525
89	(392) Transportation Equipment	10,991,498	5,581,674
90	(393) Stores Equipment	1,155,223	143,580
91	(394) Tools, Shop and Garage Equipment	5,154,881	756,722
92	(395) Laboratory Equipment	3,833,124	
93	(396) Power Operated Equipment	4,400,059	109,219
94	(397) Communication Equipment	79,362,950	2,534,426
95	(398) Miscellaneous Equipment	195,179	8,465
96	SUBTOTAL (Enter Total of lines 86 thru 95)	211,653,001	12,347,204
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	211,653,001	12,347,204
100	TOTAL (Accounts 101 and 106)	4,415,098,656	94,625,900
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	4,415,098,656	94,625,900

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			100,000		2
			4,677,060		3
1,254,312			69,679,898		4
1,254,312			74,456,958		5
					6
					7
			10,588,130		8
5,036,591			194,713,717		9
66,172,913			1,076,098,277		10
					11
17,379,254			152,455,844		12
25,917,551			130,523,659		13
269,787		-654,727	10,091,941		14
2,105,586			48,296,168		15
116,881,682		-654,727	1,622,767,736		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
17,900			3,687,554		27
1,566			20,618,168		28
24,044			129,786,670		29
64,320			33,557,530		30
20,242			20,781,277		31
			1,809,097		32
			436,270		33
					34
128,072			210,676,566		35
					36
			1,481,927		37
15,655			52,643,685		38
					39
					40
524,624			732,703,256		41
			49,658,308		42
			3,220,843		43
			11,124,296		44
540,279			850,832,315		45
117,550,033		-654,727	2,684,276,617		46

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			15,964,551		48
51,781			20,827,223		49
3,706,003			318,897,056		50
4,352			26,052,506		51
469,089			274,205,568		52
152,519			121,529,561		53
					54
			2,988,455		55
			58,614		56
					57
4,383,744			780,523,534		58
					59
			4,290,508		60
20,656			11,673,027		61
710,850			92,521,665		62
					63
640,464			115,358,251		64
975,187			94,845,414		65
4,127			12,312,613		66
565,545			103,014,278		67
510,697			93,026,260		68
173,905			18,407,250		69
2,586,097			64,315,977		70
					71
79,632			2,081,642		72
84,321			4,426,060		73
					74
6,351,481			616,272,945		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			3,302,212		86
2,866,576			77,311,440		87
1,365,573			24,927,404		88
3,126,407		390,024	13,836,789		89
			1,298,803		90
23,326		252,288	6,140,565		91
149,598			3,683,526		92
7,088		12,415	4,514,605		93
540,201			81,357,175		94
8,482			195,162		95
8,087,251		654,727	216,567,681		96
					97
					98
8,087,251		654,727	216,567,681		99
137,626,821			4,372,097,735		100
					101
					102
					103
137,626,821			4,372,097,735		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Transmission Plant			
23	115kV Boswell - Grand Rapids Line #29	8/82	12/31/2029	19,426
24				
25				
26				
27				
28				
29				
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31				
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33				
34				
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45				
46				
47	Total			19,426

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Minor Generation	8,037,246
2	Natural Gas Initiative	4,485,567
3	BEC4 - Environmental Retrofit	1,808,847
4	BEC3 - Dry Ash Handling System Final	1,259,056
5	Sylvan Increase Spill Capacity	1,104,788
6	Island Lake Sluice Gate Replacement	1,086,848
7	Minor Transmission	6,168,458
8	Great Northern Transmission Line	189,265,314
9	North Shore SVC	8,029,765
10	Boswell 230/115kV Expansion Project	7,524,058
11	Spare 138/115 kV Hoyt Lakes Transfer	1,172,309
12	Minor Distribution	5,985,356
13	Meter Data Management System	1,388,795
14	Minor General Plant	5,743,356
15	General Office Building Remodel	1,532,467
16	TAIT Dispatch Consoles	1,026,962
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
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42		
43	TOTAL	245,619,192

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,441,683,254	1,441,663,271	19,983	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	147,561,954	147,561,573	381	
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,229,411	1,229,411		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,049,511	1,049,511		
7	Other Clearing Accounts	5,482,506	5,482,506		
8	Other Accounts (Specify, details in footnote):	1,750,806	1,750,806		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	157,074,188	157,073,807	381	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	139,078,587	139,078,587		
13	Cost of Removal	5,088,415	5,088,415		
14	Salvage (Credit)	3,865,327	3,865,327		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	140,301,675	140,301,675		
16	Other Debit or Cr. Items (Describe, details in footnote):	9,949,744	9,949,744		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,468,405,511	1,468,385,147	20,364	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	653,941,926	653,941,926		
21	Nuclear Production				
22	Hydraulic Production-Conventional	36,004,462	36,004,462		
23	Hydraulic Production-Pumped Storage				
24	Other Production	131,011,216	131,011,216		
25	Transmission	249,225,439	249,205,075	20,364	
26	Distribution	284,179,228	284,179,228		
27	Regional Transmission and Market Operation				
28	General	114,043,240	114,043,240		
29	TOTAL (Enter Total of lines 20 thru 28)	1,468,405,511	1,468,385,147	20,364	

Schedule Page: 219 Line No.: 8 Column: b

Non-Regulated Depreciation Expense: $1,750,806

Schedule Page: 219 Line No.: 16 Column: b

Amount includes $14,195,248 of reclassification of undepreciated balance of Boswell Energy Center to a regulated asset and $(7,271,892) Asset Retirement Obligations & Cost of Removal Accounting Entries.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	SUPERIOR WATER, LIGHT AND POWER COMPANY			
2	Common Stock			5,800,000
3	Other Paid in Capital			8,778,221
4	Retained Earnings at Acquisition			427,507
5	Equity in Retained Earnings			35,898,189
6	SUBTOTAL			50,903,917
7	ALLETE WATER SERVICES, INC.			
8	Capital Stock			10,001
9	Other Paid in Capital			-3,310,933
10	Equity in Retained Earnings			3,575,557
11	SUBTOTAL			274,625
12	RENDFIELD LAND COMPANY, INC.			
13	Common Stock			300,000
14	Other Paid in Capital			7,001,448
15	Equity in Retained Earnings			-5,398,927
16	SUBTOTAL			1,902,521
17	LAKEVIEW FINANCIAL CORPORATION I			
18	Capital Stock			10,000
19	Other Paid in Capital			849,627
20	Equity in Retained Earnings			-859,627
21	SUBTOTAL			
22	ALLETE AUTOMOTIVE SERVICES, LLC			
23	Capital Stock			343,141
24	Equity in Retained Earnings			-343,141
25	SUBTOTAL			
26	ALLETE ENTERPRISES, INC.			
27	Capital Stock			10,000
28	Other Paid in Capital			433,814,707
29	Equity in Retained Earnings			239,047,304
30	SUBTOTAL			672,872,011
31	ALLETE PROPERTIES, LLC			
32	Capital Stock			10,000
33	Other Paid in Capital			101,316,910
34	Equity in Retained Earnings			-32,582,164
35	SUBTOTAL			68,744,746
36	MP INVESTMENTS, INC.			
37	Capital Stock			10,000
38	Other Paid in Capital			43,298,866
39	Equity in Retained Earnings			-43,292,965
40	SUBTOTAL			15,901
41				
42	Total Cost of Account 123.1 $ 623,247,415		TOTAL	794,713,721

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		5,800,000		2
		8,660,234		3
		427,507		4
3,774,766	-2,500,000	37,172,955		5
3,774,766	-2,500,000	52,060,696		6
				7
		10,001		8
		-3,314,686		9
1,687		3,577,244		10
1,687		272,559		11
				12
		300,000		13
		7,233,251		14
-312,238		-5,711,165		15
-312,238		1,822,086		16
				17
		10,000		18
		849,627		19
		-859,627		20
				21
				22
		343,141		23
		-343,141		24
				25
				26
		10,000		27
		458,307,347		28
55,843,766	-7,000,000	288,578,166		29
55,843,766	-7,000,000	746,895,513		30
				31
		10,000		32
		101,316,910		33
-507,011	-8,000,000	-41,089,175		34
-507,011	-8,000,000	60,237,735		35
				36
		10,000		37
		43,274,082		38
7,745		-43,285,220		39
7,745		-1,138		40
				41
58,808,715	-17,500,000	861,287,451		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	34,846,282	25,994,422	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	7,137,620	6,694,604	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	16,191,760	15,922,705	Electric
8	Transmission Plant (Estimated)	3,406,960	3,092,323	Electric
9	Distribution Plant (Estimated)	1,227,847	1,237,198	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	27,964,187	26,946,830	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	62,810,469	52,941,252	

Schedule Page: 227   Line No.: 7   Column: b

Amount includes $1,298,444 non-regulated Production Plant (Rapids Energy Center).

Schedule Page: 227   Line No.: 7   Column: c

Amount includes $1,301,248 non-regulated Production Plant (Rapids Energy Center).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	199,263.00		23,160.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	5,558.00		15,924.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	From: Milton R Young	3,497.00			
10					
11					
12					
13					
14					
15	Total	3,497.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,538.00			
19	Other:				
20	Surrender-Consent Decree	18,728.00			
21	Cost of Sales/Transfers:				
22	To: Milton R Young	1,793.00			
23	To: Northshore Mining	362.00			
24	Silver Bay Power				
25					
26					
27					
28	Total	2,155.00			
29	Balance-End of Year	180,897.00		39,084.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)	362.00	905		
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
23,160.00		23,160.00		602,160.00		870,903.00		1
								2
								3
12,427.00		11,788.00		33,646.00		79,343.00		4
								5
								6
								7
								8
						3,497.00		9
								10
								11
								12
								13
								14
						3,497.00		15
								16
								17
						6,538.00		18
								19
						18,728.00		20
								21
						1,793.00		22
						362.00		23
								24
								25
								26
								27
						2,155.00		28
35,587.00		34,948.00		635,806.00		926,322.00		29
								30
								31
								32
						362.00	905	33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	16,640.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	5,253.00		8,575.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	4,536.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	To: Northshore Mining				
23	Silver Bay Power	692.00			
24					
25					
26					
27					
28	Total	692.00			
29	Balance-End of Year	16,665.00		8,575.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)	692.00	1,903		
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						16,640.00		1
								2
								3
8,575.00		8,144.00		7,266.00		37,813.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,536.00		18
								19
								20
								21
								22
						692.00		23
								24
								25
								26
								27
						692.00		28
8,575.00		8,144.00		7,266.00		49,225.00		29
								30
								31
								32
						692.00	1,903	33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Interconnection - Bison	1,339	561.7		
23					
24					
25					
26					
27					
28					
29					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Net of Tax AFUDC in Plant	17,683,741	3,525,364	var.	8,802,952	12,406,153
2						
3	Asset Retirement Obligation Deferrals	29,633,317	9,018,376		6,007,900	32,643,793
4						
5	Acquisition Costs for Wind Project	672,466		407.3	74,712	597,754
6						
7	Medicare Part D	4,991,586		926	17,332	4,974,254
8						
9	ASC 715:					
10	Pension	193,995,330	6,390,679	var.	11,228,448	189,157,561
11	Retirement	12,781,467	3,955,279	var.	132,419	16,604,327
12	Supplemental Executive Retirement Plan	6,623,798	125,516	var.	1,251,397	5,497,917
13						
14	Other Deferred Taxes	92,777,439	11,258,638	283	13,141,292	90,894,785
15						
16	Boswell Energy Center 1 & 2		16,300,833	108		16,300,833
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	359,159,144	50,574,685		40,656,452	369,077,377

Schedule Page: 232 Line No.: 1 Column: a

Net of Tax AFUDC in Plant. These assets are offsets to deferred income taxes recognized on certain regulatory temporary differences, which will reverse over the remaining lives of the related assets.

Schedule Page: 232 Line No.: 3 Column: a

Asset Retirement Obligation Deferrals. These assets will accrete and be amortized over the lives of the related property with asset retirement obligations.

Schedule Page: 232 Line No.: 5 Column: a

Acquisition Costs for Wind Projects. These assets are amortized over the life of the related property, plant and equipment.

Schedule Page: 232 Line No.: 7 Column: a

Medicare Part D. This regulatory asset will be amortized over 24 years as ordered in MPUC docket number GR-16-664.

Schedule Page: 232 Line No.: 9 Column: a

Accounting Standards Codification (ASC) 715. Defined benefit pension and other postretirement items included in Minnesota Power's regulated operations, which are otherwise required to be recognized in accumulated other comprehensive income, including actuarial gains and losses as well as prior service costs and credits are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost.

Schedule Page: 232 Line No.: 14 Column: a

Other Deferred Taxes. These assets are offsets to deferred income taxes recognized on certain regulatory temporary differences, which will reverse over the remaining lives of the related assets.

Schedule Page: 232 Line No.: 16 Column: a

Boswell Energy Center Units 1 and 2. In December 2018, Minnesota Power retired Boswell Units 1 and 2 and reclassified the remaining net book value from property, plant and equipment to a regulatory asset on the Consolidated Balance Sheet. The remaining net book value is currently included in Minnesota Power’s rate base and Minnesota Power is earning a return on the outstanding balance. This balance will be amortized through 2022 based on Minnesota Power's 2016 general retail rate case.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Corporate Owned Life Insurance	20,041,383	8,650,333	426.2	7,739,208	20,952,508
2						
3	Other Postretirement Benefit	2,976,634	3,103,196	var.	5,646,321	433,509
4	Plans					
5						
6	Conservation Improvement	3,250,195		var.	3,250,195	
7	Program Tracker					
8						
9	Municipal Deferred Contract	4,142,997	2,338,747	var.	1,261,098	5,220,646
10	Incentive Payment					
11	Amortization ending 12/31/2024					
12						
13	Industrial Deferred Contract	27,464,206		443	1,961,723	25,502,483
14	Incentive Payment					
15	Amortization ending 12/31/2031					
16						
17	Workers Compensation Deposit	100,000				100,000
18						
19	Windsense Program Tracker	115,767		555	29,373	86,394
20						
21	SolarSense Program Tracker	255,267		var.	255,267	
22						
23	Mutual Aid Receivable	240,000	1,824,933	415	2,064,933	
24						
25	Miscellaneous	101,928	643,844	var.	662,047	83,725
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	58,688,377				52,379,265

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	AFDC - FAS 109	30,565	
3	Bad Debt Expense	71,855	71,855
4	Boswell Transmission Agreement	687,555	567,833
5	Property Related	59,042,765	61,490,291
6			
7	Other - Footnote Detail (1)	512,719,585	487,932,120
8	TOTAL Electric (Enter Total of lines 2 thru 7)	572,552,325	550,062,099
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify) - Footnote Detail (2)	28,509,186	28,749,774
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	601,061,511	578,811,873

Notes

Schedule Page: 234 Line No.: 7 Column: a

(1) Electric Other	**Balance at Beginning of Year**	**Balance at End of Year**
Accrued Vacation	$1,501,925	$1,383,777
Asset Retirement Obligation Accretion	(2,739,427)	(4,050,041)
Asset Retirement Obligation Regulatory Asset Amortization	159,527	159,527
Deferred Executive Plans	12,854,025	12,349,422
Executive Incentive Plan Death Benefit	441,949	440,768
Investment Tax Credits Regulatory Liability	4,043,575	4,220,040
Medical Claims	74,170	-
Midcontinent Independent System Operator Reserve	71,034	1,795,554
Net Operating Loss and Tax Credit Carryforward	291,690,960	312,648,142
Environmental Remediation	193,521	97,104
Pension Expense	38,929,464	35,391,980
Performance Shares - FAS123R	222,473	207,242
Postretirement Benefits - FAS 106	2,814,636	3,793,493
Postemployment Benefits - FAS 112	951,354	847,200
Rate Case Reserve	9,283,666	-
Regulatory Difference - Effect of Rate Changes	138,252,589	104,535,272
Regulatory Difference - Investment Tax Credit Gross-Up	13,152,289	12,905,937
Unrealized Book Losses	44,110	366,845
Other	777,745	839,858
Total	$512,719,585	$487,932,120

Schedule Page: 234 Line No.: 8 Column: c

Remeasurement due to Tax Cuts and Jobs Act

Account 190 was remeasured as a result of the Tax Cuts and Jobs Act to reflect the revised federal income tax rate. The remeasurement resulted in an excess deferred tax asset which was grossed up to a pretax amount and recorded in account 182.3. The current year reversal of the excess deferred tax asset, and the remaining excess deferred tax, are shown below, categorized by protected and unprotected. The protected amount will reverse using the average rate assumption method over the remaining lives of the related assets. The unprotected amount will be amortized over 10 years. The excess ADIT is amortized to accounts 410.1 and 411.1.

	Beginning Excess Deferred Tax:	Current Year ADIT Reversal:	Remaining Excess Deferred Tax:
Protected	$57,556,813	$1,577,890	$55,978,923
Unprotected	29,484,912	2,948,491	26,536,421
	$87,041,725	$4,526,381	$82,515,344

Schedule Page: 234 Line No.: 17 Column: a

(2) Other	**Balance at Beginning of Year**	**Balance at End of Year**
Accrued Vacation	$(7,394)	$(15,253)
Deferred Compensation Plans	1,639,049	1,580,124
Executive Incentive Plan Death Benefits	254,368	254,585
Net Operating Loss and Tax Credit Carryforward	20,844,019	21,849,022
Pension Expense	3,865,851	3,375,104
Performance Shares	788,934	787,052
Portfolio	287,420	-
Postretirement Benefits - FAS 106	626,311	713,373
Postemployment Benefits - FAS 112	159,962	147,089
Other	50,666	58,678
Total	$28,509,186	$28,749,774

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	COMMON (New York Stock Exchange)	80,000,000		
2				
3	TOTAL COMMON	80,000,000		
4				
5				
6				
7	PREFERRED			
8	5% Preferred - $100 Par Value	116,000	100.00	
9	Serial Preferred - No Par Value	1,000,000		
10	Serial Preferred A - No Par Value	2,500,000		
11				
12	TOTAL PREFERRED	3,616,000		
13				
14				
15				
16				
17				
18				
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Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
51,509,133	1,373,027,275					1
						2
51,509,133	1,373,027,275					3
						4
						5
						6
						7
						8
						9
						10
						11
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						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	GAIN ON RESALE OR CANCELLATION OF REACQUIRED CAPITAL STOCK (210)	
2		
3	Balance at Beginning of Year	-13,890,266
4		
5	Reacquired Common Stock	
6		
7	SUBTOTAL - Account 210	-13,890,266
8		
9		
10	MISCELLANEOUS PAID-IN CAPITAL (211)	
11		
12	Balance at Begining of Year	69,244,024
13		
14	Miscellaneous Paid-in Capital on Common Stock	-336,609
15	Performance Shares / Restricted Stock Unit	373,707
16		
17	SUBTOTAL - Account 211	69,281,122
18		
19		
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28		
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38		
39		
40	TOTAL	55,390,856

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	FIRST MORTGAGE BONDS		
3	First Mortgage Bonds, 5.28% Series due August 1, 2020	35,000,000	438,548
4			
5	First Mortgage Bonds, 5.99% Series due February 1, 2027	60,000,000	466,444
6			
7	First Mortgage Bonds, 6.02% Series due May 1, 2023	75,000,000	596,230
8			
9	First Mortgage Bonds, 8.17% Series due January 15, 2019	42,000,000	407,206
10			
11	First Mortgage Bonds, 5.69% Series due March 1, 2036	50,000,000	426,869
12			
13	First Mortgage Bonds, 4.85% Series due April 15, 2021	15,000,000	137,581
14			
15	First Mortgage Bonds, 5.10% Series due April 15, 2025	30,000,000	275,163
16			
17	First Mortgage Bonds, 6.00% Series due April 15, 2040	35,000,000	321,023
18			
19	First Mortgage Bonds, 4.90% Series due October 15, 2025	30,000,000	271,599
20			
21	First Mortgage Bonds, 5.82% Series due April 15, 2040	45,000,000	407,399
22			
23	First Mortgage Bonds, 3.20% Series due July 15, 2026	75,000,000	594,869
24			
25	First Mortgage Bonds, 4.08% Series due July 15, 2042	85,000,000	674,185
26			
27	First Mortgage Bonds, 1.83% Series due April 15, 2018	50,000,000	442,527
28			
29	First Mortgage Bonds, 3.30% Series due October 15, 2028	40,000,000	354,101
30			
31	First Mortgage Bonds, 4.21% Series due October 15, 2043	60,000,000	531,086
32			
33	TOTAL	1,449,401,361	12,207,231

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	FIRST MORTGAGE BONDS Continued		
2			
3	First Mortgage Bonds, 3.69% Series due March 15, 2024	60,000,000	519,384
4			
5	First Mortgage Bonds, 4.95% Series due March 15, 2044	40,000,000	344,485
6			
7	First Mortgage Bonds, 5.05% Series due July 15, 2044	40,000,000	344,475
8			
9	First Mortgage Bonds, 3.40% Series due July 15, 2022	75,000,000	650,230
10			
11	First Mortgage Bonds, 3.02% Series due September 15, 2021	60,000,000	479,152
12			
13	First Mortgage Bonds, 3.74% Series due September 15, 2029	50,000,000	399,293
14			
15	First Mortgage Bonds, 4.39% Series due September 15, 2044	50,000,000	399,293
16			
17	First Mortgage Bonds, 2.80% Series due September 15, 2020	40,000,000	347,447
18			
19	First Mortgage Bonds, 3.86% Series due September 16, 2030	60,000,000	521,170
20			
21	First Mortgage Bonds, 4.07% Series due April 16, 2048	60,000,000	591,682
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,449,401,361	12,207,231

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	INDUSTRIAL DEVELOPMENT REVENUE BONDS		
3	Collier County Industrial Development		
4	Demand Refunding Revenue Bonds Variable		
5	due October 1, 2025	27,800,000	468,251
6			
7	VARIABLE DEMAND REVENUE BONDS		
8	City of Cohasset, MN		
9	Variable Rate Demand Revenue Refunding Bonds		
10	Series A - due June 1, 2020	24,630,000	232,971
11			
12	OTHER		
13	Senior Unsecured Notes, 3.11%		
14	due June 1, 2027	80,000,000	511,655
15			
16			
17	Unsecured Term Loan Variable Rate		
18	due August 25, 2020	40,000,000	52,913
19			
20	SUBTOTAL - Account 221	1,434,430,000	12,207,231
21			
22	Solar Financing Camp Ripley		
23	CoBank, 3.11%		
24	due December 31, 2026	14,971,361	
25			
26	SUBTOTAL - Account 224	14,971,361	
27			
28			
29			
30			
31			
32			
33	TOTAL	1,449,401,361	12,207,231

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
08/01/05	08/01/20	08/01/05	08/01/20	35,000,000	1,848,000	3
						4
02/01/07	02/01/27	02/01/07	02/01/27	60,000,000	3,594,000	5
						6
05/14/08	05/01/23	05/14/08	05/01/23	75,000,000	4,515,000	7
						8
01/15/09	01/15/19	01/15/09	01/15/19	42,000,000	3,431,400	9
						10
03/01/06	03/01/36	03/01/06	03/01/36	50,000,000	2,845,000	11
						12
02/17/10	04/15/21	02/17/10	04/15/21	15,000,000	727,500	13
						14
02/17/10	04/15/25	02/17/10	04/15/25	30,000,000	1,530,000	15
						16
02/17/10	04/15/40	02/17/10	04/15/40	35,000,000	2,100,000	17
						18
08/17/10	10/15/25	08/17/10	10/15/25	30,000,000	1,470,000	19
						20
08/17/10	04/15/40	08/17/10	04/15/40	45,000,000	2,619,000	21
						22
07/02/12	07/15/26	07/02/12	07/15/26	75,000,000	2,400,000	23
						24
07/02/12	07/15/42	07/02/12	07/15/42	85,000,000	3,468,000	25
						26
04/02/13	04/15/18	04/02/13	04/15/18		266,875	27
						28
04/02/13	10/15/28	04/02/13	10/15/28	40,000,000	1,320,000	29
						30
04/02/13	10/15/43	04/02/13	10/15/43	60,000,000	2,526,000	31
						32
				1,356,390,677	58,930,907	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
03/04/14	03/15/24	03/04/14	03/15/24	60,000,000	2,214,000	3
						4
03/04/14	03/15/44	03/04/14	03/15/44	40,000,000	1,980,000	5
						6
06/26/14	07/15/44	06/26/14	07/15/44	40,000,000	2,020,000	7
						8
06/26/14	07/15/22	06/26/14	07/15/22	75,000,000	2,550,000	9
						10
09/16/14	09/15/21	09/16/14	09/15/21	60,000,000	1,812,000	11
						12
09/16/14	09/15/29	09/16/14	09/15/29	50,000,000	1,870,000	13
						14
09/16/14	09/15/44	09/16/14	09/15/44	50,000,000	2,195,000	15
						16
09/24/15	09/15/20	09/24/15	09/15/20	40,000,000	1,120,000	17
						18
09/24/15	09/16/30	09/24/15	09/16/30	60,000,000	2,316,000	19
						20
04/16/18	04/16/48	04/16/18	04/16/48	60,000,000	1,729,750	21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,356,390,677	58,930,907	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
07/01/06	10/01/25	07/01/06	10/01/25	27,800,000	407,937	5
						6
						7
						8
						9
06/01/97	06/01/20	06/01/97	06/01/20	13,500,000	206,354	10
						11
						12
						13
06/01/17	06/01/27	06/01/17	06/01/27	80,000,000	2,488,000	14
						15
						16
						17
08/25/17	08/25/20	08/25/17	08/25/20	10,000,000	937,808	18
						19
				1,343,300,000	58,507,624	20
						21
						22
						23
12/31/16	12/31/26	12/31/16	12/31/26	13,090,677	423,283	24
						25
				13,090,677	423,283	26
						27
						28
						29
						30
						31
						32
				1,356,390,677	58,930,907	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	174,085,165
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	611,373
6	Provision for Income Tax	-20,386,715
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnotes	92,172,168
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnotes	-71,980,383
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnotes	-72,643,322
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	101,858,286
28	Show Computation of Tax:	
29		
30	Tax at 21%	21,390,240
31	Add:	
32	Adjustments of Prior Year Accruals	-254
33	Fed Impact of State Current Tax Deduction	-2,081
34	Fuels Tax Credit	-1,000
35	Production Tax Credit	-36,444,410
36	Research Credit	-20,000
37	Current Year NOL Utilization	-21,388,159
38	Reclass of Federal Credits to Deferred (YTD)	36,464,410
39		
40	Total Federal Income Taxes	-1,254
41		
42		
43		
44		

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted for Return:

Depreciation - Book > Tax	$60,294,251
FAS 158 - Monthly	9,320,208
MISO Reserve	6,000,000
Interest Capitalized	5,478,243
Conservation Improvement Project	4,769,456
FAS 158 - OCI Adjustment	1,644,732
Unrealized Gains / Losses	1,122,869
State ITC Regulatory Liability	613,966
Capitalized Overheads	580,000
Property Taxes	552,069
Political Activities	350,000
Accrued Vacation	257,713
Bond Issue Cost	239,272
OPEB - FAS 106 Operating	207,440
Meals 50% Disallowance	179,785
Deferred Directors Fees	175,312
Non-Deductible Dues	150,000
Depreciation Gain / Loss	143,635
Other	93,217
TOTAL	$92,172,168

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded on Books Not Included in Return:

Equity in Subs	$(58,808,715)
Tax Over Book Gain / Loss on Sale and Retirements - Tax	(8,813,097)
AFUDC - Equity	(2,686,773)
AFUDC - Debt	(872,863)
Officers' Life Insurance	(729,935)
Fuel Clause Adjustment	(69,000)
TOTAL	$(71,980,383)

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged Against Book Income:

Rate Case Reserve	$(32,300,000)
Pension Expense - Operating	(19,540,600)
Cost to Retire	(5,430,903)
Asset Retirement Obligations Accretion	(4,559,925)
Retirement Savings and Stock Ownership Plan	(3,912,616)
Performance Shares - FAS 123R	(1,916,049)
Deferred Non-Qualified Plans	(1,441,795)
Research and Development 174 Deduction	(954,958)
Donation of Land	(841,826)
Boswell - Transmission Agreement	(416,538)
Accrued Post Employee benefit FAS 112	(407,163)
Environmental Reserves	(335,459)
Other	(223,422)
Prepiad Insurance	(200,832)
Medical Claims	(161,236)
TOTAL	$(72,643,322)

ALLETE, Inc. is a member of an affiliated group that will file a consolidated Federal Income Tax Return for the year 2018. The other members of the affiliated group and the current Federal Income Tax Provision of each are:

ALLETE Enterprises, Inc., Consolidated	$1,788,345
ALLETE Water Services, Inc., Consolidated	449
MP Investments, Inc.	(18,224)
Rendfield Land Co., Incorporated	(83,000)
Superior Water, Light and Power Company	(803,814)
ALLETE Properties, Consolidated	(1,816,666)
TOTAL	$(932,910)

The consolidated Federal Income Tax Liability has been allocated on a separate return basis with a 100% allocation of the excess, in accordance with Internal Revenue Code Section 1552 (a) (2) and IRS Regulation Section 1.1502-33 (d) (2) (ii).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal - Income	-9,272,087		-1,254	-1,959,185	
2	Federal - Old Age Benefits	335,771		7,866,810	7,882,611	
3	Federal - Unemployment Ins.			49,291	49,291	
4	Federal - Motor Veh. Hwy.			2,489	2,489	
5	SUBTOTAL - Federal	-8,936,316		7,917,336	5,975,206	
6						
7	MN - Income	-1,557,029		9,885	-998,512	
8	MN - Unemployment Ins.			150,753	150,753	
9	MN - Solar Production Tax	20,480		19,730	20,478	
10	MN - Air Quality Emission Fee	595,807		1,286,033	1,273,252	
11	MN - Wind Production Tax	67,916		60,973	67,913	
12	SUBTOTAL - Minnesota	-872,826		1,527,374	513,884	
13						
14	State of WI - Income	-575		25	-125	
15	State of ND - Income					
16	Other States - Income	-39,025			88,840	
17	SUBTOTAL - Other States	-39,600		25	88,715	
18						
19	Pers. Prop. - 2018			17,904,170		
20	Pers. Prop. - 2017 & Prior	19,850,267		202,918	17,923,945	
21	SUBTOTAL - Pers. Prop.	19,850,267		18,107,088	17,923,945	
22						
23	Real Estate - 2018			24,500,312	-3,387,738	
24	Real Estate - 2017 & Prior	26,314,604		674,293	26,988,897	
25	SUBTOTAL - Real Estate	26,314,604		25,174,605	23,601,159	
26						
27	Misc. Accrued Taxes	-2		2		
28	Duluth Ordinance	248,772		3,123,996	3,141,692	
29	Long Prairie Franchise Fee	7,527		30,063	30,065	
30	Little Falls Franchise Fee	21,259		84,685	84,831	
31	Hermantown Franchise Fee	25,248		101,717	101,381	
32	Park Rapids Franchise Fee	22,322		89,978	89,840	
33	Aurora Franchise Fee	5,787		23,156	23,203	
34	Staples Franchise Fee	1			1	
35	Nashwauk Franchise Fee	615		7,224	7,176	
36	Silver Bay Franchise Fee	3,103		37,419	43,393	
37	Hoyt Lakes Franchise Fee	9,879		39,176	39,270	
38	Upsula Franchise Fee	4,144		16,606	16,593	
39	SUBTOTAL - Local	348,655		3,554,022	3,577,445	
40						
41	TOTAL	36,664,784		56,280,450	51,680,354	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
-7,314,156		-1,254				1
319,970		5,360,621			2,506,189	2
		33,588			15,703	3
					2,489	4
-6,994,186		5,392,955			2,524,381	5
						6
-548,632		9,960			-75	7
		102,726			48,027	8
19,732		19,730				9
608,588		1,286,033				10
60,976		60,973				11
140,664		1,479,422			47,952	12
						13
-425		25				14
						15
-127,865						16
-128,290		25				17
						18
17,904,170		17,904,170				19
2,129,240		202,918				20
20,033,410		18,107,088				21
						22
27,888,050		23,560,708			939,604	23
		669,319			4,974	24
27,888,050		24,230,027			944,578	25
						26
					2	27
231,076					3,123,996	28
7,525					30,063	29
21,113					84,685	30
25,584					101,717	31
22,460					89,978	32
5,740					23,156	33
						34
663					7,224	35
-2,871					37,419	36
9,785					39,176	37
4,157					16,606	38
325,232					3,554,022	39
						40
41,264,880		49,209,517			7,070,933	41

Schedule Page: 262 Line No.: 2 Column: l

Federal - Old Age Benefits	Account No. 408.2	$482,186
	Account No. Other	2,024,003
		$2,506,189

Schedule Page: 262 Line No.: 23 Column: l

Real Estate - 2018	Account No. 408.2	$932,022
	Account No. Other	7,582
		$939,604

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	208,282			411.4	15,591	
4	7%						
5	10%	7,518,870			411.4	581,234	
6	30%	24,880,384	190	-6,945	411.4	6,993	
7							
8	TOTAL	32,607,536		-6,945		603,818	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
192,691	42		3
			4
6,937,636	33		5
24,866,446	46		6
			7
31,996,773			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			33
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			45
			46
			47
			48

Schedule Page: 266 Line No.: 3 Column: b

Average Amortization Period	**Years**
Transmission Plant	51
Distribution Plant	42
Steam Plant	38
Hydro Plant	36

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Directors' Fees	1,702,450	930.2	199,564	378,516	1,881,402
2						
3	Executive Incentive Plan	831,201	var.	278,658	34,274	586,817
4						
5	Miscellaneous Retirement Benefits	1,512,277	var.	158,541	89,476	1,443,212
6						
7	Transmission Delivery Charge-	2,392,160	456	416,538		1,975,622
8	Boswell Sale					
9						
10	Deferrals Supplemental Executive	20,497,652	var.	3,593,151	2,813,029	19,717,530
11	Retirement Plan					
12						
13	FIN 48 - Income Tax Non-Current	505,715	var.	29,989	61,364	537,090
14						
15	Labor Allocations	87	var.	22,349,204	22,348,832	-285
16						
17	Miscellaneous	804,523	var.	1,423,233	1,107,932	489,222
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	28,246,065		28,448,878	26,833,423	26,630,610

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	87,645,512	1,329,082	3,943,037
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	87,645,512	1,329,082	3,943,037
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	87,645,512	1,329,082	3,943,037
18	Classification of TOTAL			
19	Federal Income Tax	66,883,462	1,010,117	3,190,928
20	State Income Tax	20,762,050	318,965	752,109
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
						85,031,557	4
							5
							6
							7
						85,031,557	8
							9
							10
							11
							12
							13
							14
							15
							16
						85,031,557	17
							18
						64,702,651	19
						20,328,906	20
							21

NOTES (Continued)

Schedule Page: 272 Line No.: 4 Column: k

Remeasurement due to Tax Cuts and Jobs Act

Account 281 was remeasured as a result of the Tax Cuts and Jobs Act to reflect the revised federal income tax rate. The remeasurement resulted in an excess deferred tax liability which was grossed up to a pretax amount and recorded in account 254. The current year reversal of the excess deferred tax liability, and the remaining excess deferred tax, are shown below, categorized by protected and unprotected. The protected amount will reverse using the average rate assumption method over the remaining lives of the related assets. The excess ADIT is amortized to accounts 410.1 and 411.1.

	Beginning Excess Deferred Tax:	Current Year ADIT Reversal:	Remaining Excess Deferred Tax:
Protected	$26,279,614	$869,837	$25,409,777
Unprotected	-	-	-
	$26,279,614	$869,837	$25,409,777

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	556,776,854	27,914,023	29,469,571
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	556,776,854	27,914,023	29,469,571
6				
7	Other	7,762,128		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	564,538,982	27,914,023	29,469,571
10	Classification of TOTAL			
11	Federal Income Tax	398,369,782	13,608,844	23,085,242
12	State Income Tax	166,169,200	14,305,179	6,384,329
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
		var.	41,265,734	var.	15,299,308	529,254,880	2
							3
							4
			41,265,734		15,299,308	529,254,880	5
							6
5,715,242	5,902,793					7,574,577	7
							8
5,715,242	5,902,793		41,265,734		15,299,308	536,829,457	9
							10
5,019,385	5,142,137		38,984,915		14,202,148	363,987,865	11
695,857	760,656		2,280,819		1,097,160	172,841,592	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: h

Electric - Adjustments - Debit

	Total	Federal	State
Account No. 182.1	$6,272,808	$4,321,611	$1,951,197
Account No. 190.3	29,660,072	29,660,072	-
Account No. 254.1	5,332,854	5,003,232	329,622
	$41,265,734	$38,984,915	$2,280,819

Schedule Page: 274 Line No.: 2 Column: j

Electric - Adjustments - Credit

	Total	Federal	State
Account No. 182.1	$2,512,104	$1,843,173	$668,931
` Account No. 254.1	12,787,204	12,358,975	428,229
	$15,299,308	$14,202,148	$1,097,160

Schedule Page: 274 Line No.: 2 Column: k

Remeasurement due to Tax Cuts and Jobs Act

Account 282 was remeasured as a result of the Tax Cuts and Jobs Act to reflect the revised federal income tax rate. The remeasurement resulted in an excess deferred tax liability which was grossed up to a pretax amount and recorded in account 254. The current year reversal of the excess deferred tax liability, and the remaining excess deferred tax, are shown below, categorized by protected and unprotected. The amounts shown below also include excess deferred taxes that existed prior to the Tax Cuts and Jobs Act as a result of prior tax rate changes. The protected amount will reverse using the average rate assumption method over the remaining lives of the related assets. The unprotected amount will be amortized over 10 years. The excess ADIT is amortized to accounts 410.1 and 411.1.

	Beginning Excess Deferred Tax:	Current Year ADIT Reversal:	Remaining Excess Deferred Tax:
Protected	$242,081,848	$9,294,294	$232,787,554
Unprotected	4,325,319	432,533	3,892,786
	$246,407,167	$9,726,827	$236,680,340

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3				
4				
5				
6				
7				
8	Other (1)	92,009,000	1,130,121	7,863,864
9	TOTAL Electric (Total of lines 3 thru 8)	92,009,000	1,130,121	7,863,864
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other (Specify) (2)	-1,293,764		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	90,715,236	1,130,121	7,863,864
20	Classification of TOTAL			
21	Federal Income Tax	67,523,547	950,200	6,347,882
22	State Income Tax	23,191,689	179,921	1,515,982
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
		var.	6,935,590	var.	9,667,264	88,006,931	8
			6,935,590		9,667,264	88,006,931	9
							10
							11
							12
							13
							14
							15
							16
							17
27,889	316,224	var.	11,820	var.	176,901	-1,417,018	18
27,889	316,224		6,947,410		9,844,165	86,589,913	19
							20
25,729	215,752		6,160,392		8,870,768	64,646,218	21
2,160	100,472		787,018		973,397	21,943,695	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: a

(1) Other Electric	Beginning Balance	Debited (410.1)	Credited (411.1)	Debits to 283 Account Credited	Debits to 283 Amount	Credits to 283 Account Debited	Credits to 283 Amount	Ending Balance
AFDC - FAS 109	$5,082,662	-	-	182	$2,530,145	182	$1,013,260	$3,565,777
Conservation Improvement Project	934,173	$98,155	$1,468,992		-		-	(436,664)
Deferred Executive Plans	818,610	18,935	1,268		-		-	836,277
Deferred Gain/Loss	41,284	2,956	44,240		-		-	-
FAS 158	62,623,032	170,711	2,554,855	219	135,932	219	2,034,359	62,137,315
Fuel Clause Adjustment	(19,834)	21,254	1,420		-		-	-
Prepaid Bison Easements	357,610	6,694	447		-		-	363,857
Prepaid Insurance	1,437,478	61,856	4,133		-		-	1,495,201
Prepayment Expense - Bonds	837,689	19,718	88,489		-		-	768,918
Property Taxes	(4,196,893)	462,387	631,724		-		-	(4,366,230)
Regulatory Asset - Medicare Part D	1,434,682	357	5,338		-		-	1,429,701
Rate Case Expense	(38,824)	20,801	1,390		-		-	(19,413)
Regulatory Assets and Liabilities	22,697,331	246,297	3,061,568	var.	4,269,513	var.	6,619,645	22,232,192
Total	$92,009,000	$1,130,121	$7,863,864		$6,935,590		$9,667,264	$88,006,931

Schedule Page: 276 Line No.: 8 Column: k

Remeasurement due to Tax Cuts and Jobs Act

Account 283 was remeasured as a result of the Tax Cuts and Jobs Act to reflect the revised federal income tax rate. The remeasurement resulted in an excess deferred tax liability which was grossed up to a pretax amount and recorded in account 254. The current year reversal of the excess deferred tax liability, and the remaining excess deferred tax, are shown below, categorized by protected and unprotected. The unprotected amount will be amortized over 10 years. The excess ADIT is amortized to accounts 410.1 and 411.1.

	Beginning Excess Deferred Tax:	Current Year ADIT Reversal:	Remaining Excess Deferred Tax:
Protected	-	-	-
Unprotected	$28,105,872	$2,810,587	$25,295,285
	$28,105,872	$2,810,587	$25,295,285

Schedule Page: 276 Line No.: 18 Column: a

(2) Other	Beginning Balance	Debited (410.2)	Credited (411.2)	Debits to 283 Account Credited	Debits to 283 Amount	Credits to 283 Account Debited	Credits to 283 Amount	Ending Balance
Audit Interest Expense	$(6,335)	$6,789	$454	-	-	-	-	-
FAS 158	(1,287,429)	21,100	315,770	219	$11,820	219	$176,901	$(1,417,018)
Total	$(1,293,764)	$27,889	$316,224		$11,820		$176,901	$(1,417,018)

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	ASC 740 Liabilities					
2	Investment Tax Credits	13,152,293	190	263,992	17,639	12,905,940
3	Net of Tax AFUDC in Plant	69,581	var.	19,431	1,894	52,044
4	Tax Over Book Depreciation	348,519,039	var.	18,903,370	8,438,310	338,053,979
5	Other Deferred Taxes	39,448,983	var.	4,278,419	327,605	35,498,169
6						
7	North Dakota Investment Tax Credits	14,068,520	var.	415,856	1,029,822	14,682,486
8						
9	Pre-funded AFUDC	57,940,047	var.	2,213,487	8,674,108	64,400,668
10						
11	Deferred Rate Case Expense	135,073	456	67,536		67,537
12	MPUC Docket No.					
13	E015/GRZ-09-1151 and GR-16-664					
14						
15	Cost Recovery Tracker Riders	2,194,151	var.	35,710,185	40,413,420	6,897,386
16						
17	Sale of Service Centers				199,919	199,919
18	MPUC Docket No.					
19	E015/PA-17-457 and PA-17-459					
20						
21	Conservation Improvement Program		var.	30,227,330	31,746,590	1,519,260
22						
23	Transmission Formula Rates				6,000,000	6,000,000
24						
25	SolarSense Program		var.	937,439	2,171,699	1,234,260
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	475,527,687		93,037,045	99,021,006	481,511,648

Schedule Page: 278 Line No.: 1 Column: a

ASC 740. These liabilities are offsets to deferred income taxes recognized on certain regulatory temporary differences, which will reverse over the remaining lives of the related assets.

Schedule Page: 278 Line No.: 4 Column: c

Tax Over Book Depreciation	Account 190	$5,697,248
	Account 282	12,773,588
	Account 283	432,534
		$18,903,370

Schedule Page: 278 Line No.: 5 Column: c

Other Deferred Taxes	Account 190	$1,216,849
	Account 283	3,061,570
		$4,278,419

Schedule Page: 278 Line No.: 7 Column: a

North Dakota Investment Tax Credits. Credits expected to be realized from Bison that will be credited to Minnesota Power's retail customers through future renewable cost recovery rider filings as the tax credits are utilized.

Schedule Page: 278 Line No.: 9 Column: a

Pre-funded AFUDC. Wholesale and Retail Contra AFUDC represents amortization to offset AFUDC Equity and Debt recorded during the construction period of our cost recovery rider projects prior to placing the projects in service. The regulatory liability will decrease over the remaining depreciable life of the related asset.

Schedule Page: 278 Line No.: 11 Column: a

Deferred Rate Case Expense. This regulatory liability will be amortized through 2019 as ordered in MPUC docket number GR-16-664.

Schedule Page: 278 Line No.: 15 Column: a

Cost Recovery Tracker Riders. This regulatory liability represents cash collections from Minnesota Power customers in excess of the revenue recognized. Any balance is expected to be returned to customers within two years. The cost recovery tracker riders included are; Transmission Tracker Rider, Renewable Tracker Rider, Environmental Improvement Rider, and Solar Tracker Rider.

Schedule Page: 278 Line No.: 17 Column: a

Sale of Service Centers. This regulatory liability represents cash collected from Minnesota Power customers related to the Aurora and Chisholm Service Centers that were sold in 2017. Costs related to these assets are incorporated in base rates and will be adjusted for in Minnesota Power's next rate case.

Schedule Page: 278 Line No.: 21 Column: a

Conservation Improvement Program. This regulatory liability represents cash collections from Minnesota Power customers in excess of CIP expenditures and financial incentives earned for cost-effective program achievements. Any balance is expected to be returned to customers over the next year.

Schedule Page: 278 Line No.: 23 Column: a

Transmission Formula Rates. This current regulatory liability represents an accrued liability for the MISO Attachment O, GG, ZZ true-up related to MISO rates billed and expected to be returned to customers in future periods.

Schedule Page: 278   Line No.: 25   Column: a

SolarSense Program. This regulatory liability represents cash collections from Minnesota Power customers in excess of SolarSense Program expenditures. Any balance is expected to be returned to customers over two years.

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	116,468,452	108,887,191
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	124,102,940	119,507,547
5	Large (or Ind.) (See Instr. 4)	430,298,865	441,769,968
6	(444) Public Street and Highway Lighting	2,467,252	2,449,194
7	(445) Other Sales to Public Authorities	4,637,432	4,505,017
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	677,974,941	677,118,917
11	(447) Sales for Resale	274,482,249	272,727,586
12	TOTAL Sales of Electricity	952,457,190	949,846,503
13	(Less) (449.1) Provision for Rate Refunds	25,121,135	31,600,000
14	TOTAL Revenues Net of Prov. for Refunds	927,336,055	918,246,503
15	Other Operating Revenues		
16	(450) Forfeited Discounts	802,231	655,218
17	(451) Miscellaneous Service Revenues	87,022	65,187
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,315,288	1,241,892
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	37,891,017	40,758,881
22	(456.1) Revenues from Transmission of Electricity of Others	53,968,678	65,524,419
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	94,064,236	108,245,597
27	TOTAL Electric Operating Revenues	1,021,400,291	1,026,492,100

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
1,052,800	1,010,955	122,557	122,295	2
				3
1,233,117	1,223,786	22,834	22,695	4
6,677,892	6,697,793	380	390	5
14,206	14,873	693	695	6
49,884	49,945	277	278	7
				8
				9
9,027,899	8,997,352	146,741	146,353	10
5,563,354	5,695,306	17	17	11
14,591,253	14,692,658	146,758	146,370	12
				13
14,591,253	14,692,658	146,758	146,370	14

Line 12, column (b) includes $ -786,635 of unbilled revenues.

Line 12, column (d) includes -11,500 MWH relating to unbilled revenues

Schedule Page: 300   Line No.: 21   Column: b

Other Electric Revenue includes the following:

Cost Recovery on Transmission Projects	$14,756,732
Steam Sales Revenue	7,157,012
Cost Recovery on Renewable Projects	5,727,555
Clean Coal Sales Revenue	3,940,798
Conservation Improvement Program Financial Incentive	2,994,840
Cost Recovery on Solar Projects	2,758,949
Coal Sales Revenue	2,161,303
Great River Energy Distribution Wheeling Revenue	2,001,340
Recreational Site Leases	737,709
Miscellaneous	731,332
Fly Ash Sales	555,614
Midcontinent Independent System Operator Reactive Supply Revenue	490,129
Cost Recovery on Environmental Projects	(6,122,296)
	$37,891,017

Schedule Page: 300   Line No.: 21   Column: c

Other Electric Revenue includes the following:

Cost Recovery on Renewable Projects	$13,276,362
Cost Recovery on Transmission Projects	9,288,018
Steam Sales Revenue	6,913,467
Conservation Improvement Program Financial Incentive	5,528,499
Great River Energy Distribution Wheeling Revenue	2,701,961
Coal Sales Revenue	2,460,451
Clean Coal Sales Revenue	1,593,966
Miscellaneous	1,044,170
Recreational Site Leases	706,925
Midcontinent Independent System Operator Reactive Supply Revenue	572,249
Fly Ash Sales	448,522
Cost Recovery on Environmental Projects	(3,775,709)
	$40,758,881

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	440 RESIDENTIAL					
3	20, 22 Residential	944,932	105,491,118	109,260	8,648	0.1116
4	21 Res. Dual Fuel Interruptible	97,111	8,670,250	7,424	13,081	0.0893
5	23 Seasonal Resident	10,149	1,527,905	3,128	3,245	0.1505
6	24 Residential Controlled Access	4,551	362,828	318	14,311	0.0797
7	28 Off-Peak Electric Vehicle	8	676	1	8,000	0.0845
8	76 Outdoor Lighting Service	13	3,291	22	591	0.2532
9	77 Area Ltg. Service	1,806	424,558	2,404	751	0.2351
10	Revenue Adjustment		398,438			
11	Windsense Program Tracker		24,067			
12	Unbilled	-5,770	-434,679			0.0753
13	TOTAL RESIDENTIAL	1,052,800	116,468,452	122,557	8,590	0.1106
14						
15	442 COMMERCIAL					
16	25 General Service	619,512	68,954,565	19,949	31,055	0.1113
17	26 Comm/Indust Dual Fuel Interr.	25,900	2,189,786	526	49,240	0.0845
18	27 Comm/Indust Controlled Access	766	63,026	56	13,679	0.0823
19	75 Large Light & Power	588,312	52,675,498	371	1,585,747	0.0895
20	76 Outdoor Ltg. Service	159	23,609	72	2,208	0.1485
21	77 Area Lg. Service	3,762	742,586	1,860	2,023	0.1974
22	Revenue Adjustment		-208,528			
23	Windsense Program Tracker		5,110			
24	Unbilled	-5,294	-342,712			0.0647
25	TOTAL COMMERCIAL	1,233,117	124,102,940	22,834	54,004	0.1006
26						
27	443 INDUSTRIAL					
28	25 General Service	26,761	2,986,873	264	101,367	0.1116
29	26 Comm/Ind Dual Fuel Inter	357	29,977	6	59,500	0.0840
30	74 Large Power	5,497,023	350,279,026	9	610,780,333	0.0637
31	75 Large Light & Power	699,052	56,912,380	56	12,483,071	0.0814
32	76 Outdoor Ltg. Service	3	559	2	1,500	0.1863
33	77 Are Ltg. Service	159	26,459	42	3,786	0.1664
34	CA Large Power	454,858	20,185,867	1	454,858,000	0.0444
35	Revenue Adjustments		-120,782			
36	Unbilled	-321	-1,494			0.0047
37	TOTAL INDUSTRIAL	6,677,892	430,298,865	380	17,573,400	0.0644
38						
39						
40						
41	TOTAL Billed	9,039,399	678,761,576	146,741	61,601	0.0751
42	Total Unbilled Rev.(See Instr. 6)	-11,500	-786,635	0	0	0.0684
43	TOTAL	9,027,899	677,974,941	146,741	61,523	0.0751

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	444 PUBLIC ST & HWY LIGHTING					
4	25 General Service	531	70,299	68	7,809	0.1324
5	77 Area Ltg. Service	276	46,898	88	3,136	0.1699
6	80 Highway Lighting	1,933	165,877	82	23,573	0.0858
7	83 Overhead Street Lighting	8,836	1,929,152	345	25,612	0.2183
8	84 Ornamental Street Lighting	2,630	255,578	110	23,909	0.0972
9	Revenue Adjustments		-552			
10	Unbilled					
11	TOTAL PUBLIC ST & HWY LTG	14,206	2,467,252	693	20,499	0.1737
12						
13	445 OTHER SALES TO PUB AUTH					
14	25 General Service	1,984	207,151	47	42,213	0.1044
15	75 Large Light & Power	35,130	3,002,318	11	3,193,636	0.0855
16	77 Area Lighting Service	6	1,106	6	1,000	0.1843
17	87 Municipal Pumping	12,879	1,438,132	213	60,465	0.1117
18	Revenue Adjustments		-3,525			
19	Unbilled	-115	-7,750			0.0674
20	TOTAL OTHER SALES/PUB AUTH	49,884	4,637,432	277	180,087	0.0930
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	9,039,399	678,761,576	146,741	61,601	0.0751
42	Total Unbilled Rev.(See Instr. 6)	-11,500	-786,635	0	0	0.0684
43	TOTAL	9,027,899	677,974,941	146,741	61,523	0.0751

Schedule Page: 304 Line No.: 1 Column: c

The following identifies fuel adjustment revenue included in column c on pages 304 and 304.1.

Number and Title of Rate Schedule	Fuel Adjustment Revenue
440 Residential	
20,22 Residential	$12,272,395
21 Residential Dual Fuel Interruptible	1,201,795
23 Seasonal Residential	135,068
24 Residential Controlled Access	55,946
28 Residential Off-Peak Electric Vehicle	102
76 Outdoor Lighting Service	114
77 Area Lighting Service	16,012
Total Residential	13,681,432
442 Commercial	
25 General Service	8,093,912
26 Commercial / Industrial Dual Fuel Interruptible	333,087
27 Commercial / Industrial Controlled Access	9,362
75 Large Light & Power	7,259,286
76 Outdoor Lighting Service	1,417
77 Area Lighting Service	33,383
Total Commercial Sales	15,730,447
443 Industrial	
25 General Service	340,804
26 Commercial / Industrial Dual Fuel Interruptible	4,497
74 Large Power	60,454,938
75 Large Light & Power	8,143,288
76 Outdoor Lighting Service	28
77 Area Lighting Service	1,414
Total Industrial	68,944,969
444 Public Street & Highway Lighting	
25 General Service	7,069
77 Area Lighting Service	2,449
80 Highway Lighting	17,289
83 Overhead Street Lighting	78,577
84 Ornamental Street Lighting	23,661
Total Public Street & Highway Ltg.	129,045
445 Other Sales To Public Authorities	
25 General Service	25,778
75 Large Light & Power	432,758
77 Area Lighting Service	51
87 Municipal Pumping	154,126
Total Other Sales To Public Authorities	612,713
Total	$99,098,606

Rider Cost Recovery

The revenue amounts in column c on pages 304 and 304.1 exclude the portion of rider cost recovery on renewable, transmission and environmental projects included in account 456 - Other Electric Revenue on Page 300 of this FERC Form 1.

Schedule Page: 304 Line No.: 1 Column: d

Customer Counts

Customer counts reported in column d include customers that may be served under more than one rate schedule in the same revenue account classification. Customer account duplications can be found in the dual fuel, seasonal, controlled access, overhead lighting and area lighting rate schedules.

- The "average customer count" is the average number of service agreements billed for 2018.
- An "account with multiple" is defined as one customer account billing with multiple rate schedules.
- A database search for duplicates was performed that compared like service addresses containing more than one rate schedule to obtain a count by rate class.

The following residential and commercial counts are approximate as one customer can have multiple accounts within the same or across rate schedules.

440: 20, 22 Residential Total – 109,260
Accounts with multiples – 9,900
The customer counts for the following rate schedules are also included in the count for rate schedule 20, 22 Residential:

- 21 – Residential Dual Fuel Interruptible – 7,400
- 23 – Seasonal Residential – 200
- 24 – Residential Controlled Access – 300
- 77 – Area Lighting – 2,000

442: 25 General Service Total – 19,949
Accounts with multiples – 2,300
The customer counts for the following rate schedules are also included in the count for rate schedule 25 General Service:

- 26 – Commercial Dual Fuel Interruptible – 500
- 27 – Commercial / Industrial Controlled Access – 100
- 75 –Large Light & Power – 100
- 77 – Area Lighting – 1,600

Customer counts for the categories Industrial, Public Street & Highway Lighting, and Other Sales to Public Authorities also contain multiple accounts and overlap between rate schedules, however, are not material.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	Municipals					
3	Superior Water, Light and Power Co	RQ	2	110.2	109.6	102.7
4	City of Aitkin	RQ	2	6.7	6.6	6.1
5	City of Biwabik	RQ	2	1.1	1.1	0.9
6	City of Brainerd	RQ	2	29.9	29.7	27.2
7	City of Buhl	RQ	2	1.1	1.1	1.0
8	City of Ely	RQ	2	6.0	5.8	5.4
9	City of Gilbert	RQ	2	1.8	1.8	1.6
10	City of Grand Rapids	RQ	2	25.8	25.6	24.2
11	City of Hibbing	RQ	2	20.6	21.4	20.4
12	City of Keewatin	RQ	2	1.0	1.0	0.8
13	City of Mt. Iron	RQ	2	2.9	2.8	2.6
14	City of Nashwauk	RQ	2	1.9	1.8	1.7
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Pierz	RQ	2	1.9	1.9	1.7
2	City of Proctor	RQ	2	4.1	4.1	3.8
3	City of Randall	RQ	2	0.9	0.9	0.8
4	City of Two Harbors	RQ	2	4.5	4.4	4.2
5	City of Virginia	RQ	2	18.2	18.3	17.4
6						
7	2018 Formula-Based Rates True-Up	RQ				
8	Prior Years Formula-Based Rates True-Up	AD				
9	Contract Incentive Amortization	RQ				
10	MISO Attachment O, GG, ZZ True-Up	AD				
11						
12	Non-Required Sales for Resale					
13	Other Nonassociated Utilities Under					
14	FERC Electric Tariff	OS	1st Rev. Vol. No.5			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
812,938	27,250,501	14,690,028	6,964,513	48,905,042	3
38,745	1,560,680	702,052	571,123	2,833,855	4
6,588	266,835	119,382	108,004	494,221	5
170,684	7,457,232	3,085,422	1,311,795	11,854,449	6
6,927	276,521	125,517	113,011	515,049	7
38,129	1,400,702	690,888	607,565	2,699,155	8
11,163	437,767	202,279	187,116	827,162	9
162,919	5,944,786	2,952,085	2,271,923	11,168,794	10
137,899	4,763,040	2,498,738	2,170,874	9,432,652	11
5,740	251,568	104,009	94,724	450,301	12
18,629	685,383	337,554	294,716	1,317,653	13
11,908	477,908	215,180	71,434	764,522	14
1,610,792	57,718,697	29,139,173	18,947,348	105,805,218	
3,952,562	45,517,038	124,757,729	-1,597,736	168,677,031	
5,563,354	**103,235,735**	**153,896,902**	**17,349,612**	**274,482,249**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
10,786	459,230	195,435	207,501	862,166	1
26,934	968,343	488,048	428,817	1,885,208	2
5,083	219,595	92,107	94,318	406,020	3
28,969	1,046,866	524,915	475,421	2,047,202	4
116,751	4,251,740	2,115,534	1,840,834	8,208,108	5
					6
			1,725,523	1,725,523	7
			2,264	2,264	8
			-591,864	-591,864	9
			-1,600,000	-1,600,000	10
					11
					12
					13
3,952,562	45,517,038	124,757,729		170,274,767	14
1,610,792	57,718,697	29,139,173	18,947,348	105,805,218	
3,952,562	45,517,038	124,757,729	-1,597,736	168,677,031	
5,563,354	**103,235,735**	**153,896,902**	**17,349,612**	**274,482,249**	

Schedule Page: 310 Line No.: 1 Column: j

Other Charges include Formula Rate True-Ups, Energy Adjustments and True-Ups, and Midcontinent Independent System Operator Network Services and Ancillary Services.

Schedule Page: 310 Line No.: 3 Column: a

Superior Water, Light and Power Company (SWL&P) is a wholly-owned subsidiary of ALLETE, Inc.

Schedule Page: 310 Line No.: 6 Column: a

In 2016, the City of Brainerd provided termination notice for its contract effective June 30, 2019.

Schedule Page: 310.1 Line No.: 7 Column: j

Formula-Based Rate True-Up includes:

	Total	2018	Prior Years
2018/2019 True-Up Accrual	$156,351	$156,351	–
2017/2018 True-Up Accrual Adjustment	(3,446,380)	(321,740)	$(3,124,640)
2017/2018 True-Up Accrual Reversal	4,625,099	1,890,912	2,734,187
2016/2017 True-Up Accrual Reversal	392,717	–	392,717
	$1,727,787	$1,725,523	$2,264

The 2018/2019 True-Up Accrual reflects an estimated amount for 2019 billings to SWL&P and municipal customers related to service provided in 2018.

The 2017/2018 True-Up Accrual Adjustment reflects an increase to the amount accrued for 2018 refunds to SWL&P and municipal customers related to service provided from July 2017 through June 2018.

The 2017/2018 True-Up Accrual Reversal reflects the reversal of the 2017 accrual and a portion of the 2018 accrual for refunds made in 2018 to SWL&P and municipal customers for service provided from July 2016 through June 2017.

The 2016/2017 True-Up Accrual Reversal reflects the reversal of the remaining 2016 accruals, and a portion of the 2017 accrual for net billings made to SWL&P in 2017 for service provided in July 2016 through June 2017.

Schedule Page: 310.1 Line No.: 8 Column: j

See footnote for Schedule Page 310.1 Line No. 7 Column J above.

Schedule Page: 310.1 Line No.: 10 Column: j

The MISO Attachment O, GG, ZZ true-up reflects an estimated out-of-period adjustment for MISO rates that were billed in 2017 and are expected to be credited to customers in 2019.

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	6,058,151	6,649,544
5	(501) Fuel	149,684,997	143,367,151
6	(502) Steam Expenses	10,562,658	11,393,393
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,822,805	1,892,677
10	(506) Miscellaneous Steam Power Expenses	800,614	553,868
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	168,929,225	163,856,633
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,357,688	4,074,056
16	(511) Maintenance of Structures	1,018,541	1,163,815
17	(512) Maintenance of Boiler Plant	9,613,150	11,731,724
18	(513) Maintenance of Electric Plant	2,713,305	3,226,061
19	(514) Maintenance of Miscellaneous Steam Plant	3,867,090	4,725,423
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	20,569,774	24,921,079
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	189,498,999	188,777,712
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	759,047	857,941
45	(536) Water for Power		
46	(537) Hydraulic Expenses	889,964	1,071,121
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	75,218	258,316
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,724,229	2,187,378
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	384,193	474,160
54	(542) Maintenance of Structures	76,957	45,560
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,317,590	1,152,771
56	(544) Maintenance of Electric Plant	1,002,687	1,016,865
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,242,398	1,306,137
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,023,825	3,995,493
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	5,748,054	6,182,871

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	369,221	36,962
63	(547) Fuel		
64	(548) Generation Expenses	149,695	149,173
65	(549) Miscellaneous Other Power Generation Expenses	1,662,388	1,672,684
66	(550) Rents	2,987,001	2,877,497
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,168,305	4,736,316
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	18,976	25,426
70	(552) Maintenance of Structures	2,964	32,835
71	(553) Maintenance of Generating and Electric Plant	9,234,251	8,000,197
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,201,046	1,580,917
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	11,457,237	9,639,375
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	16,625,542	14,375,691
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	256,053,067	235,520,741
77	(556) System Control and Load Dispatching	427,408	351,120
78	(557) Other Expenses	1,220,715	1,264,715
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	257,701,190	237,136,576
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	469,573,785	446,472,850
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,054,076	2,352,748
84			
85	(561.1) Load Dispatch-Reliability	1,827,532	2,292,084
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,146,827	3,581,505
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	2,029,704	1,961,971
89	(561.5) Reliability, Planning and Standards Development	626,635	666,610
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	1,339	
92	(561.8) Reliability, Planning and Standards Development Services	145,941	141,072
93	(562) Station Expenses	191,740	117,460
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	67,904,601	69,267,830
97	(566) Miscellaneous Transmission Expenses	1,387,057	1,054,339
98	(567) Rents	1,904,196	1,769,133
99	TOTAL Operation (Enter Total of lines 83 thru 98)	82,219,648	83,204,752
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	3,851	1,715
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		5,659
105	(569.3) Maintenance of Communication Equipment	1,844,050	2,652,785
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,585,173	3,395,562
108	(571) Maintenance of Overhead Lines	2,209,888	2,894,329
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	53,996	125,812
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,696,958	9,075,862
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	89,916,606	92,280,614

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,087,316	1,145,188
135	(581) Load Dispatching	291,245	669,892
136	(582) Station Expenses	2,755	233
137	(583) Overhead Line Expenses	152,185	217,481
138	(584) Underground Line Expenses	68,030	50,351
139	(585) Street Lighting and Signal System Expenses	142,915	148,155
140	(586) Meter Expenses	289,542	316,664
141	(587) Customer Installations Expenses	1,147	1,065
142	(588) Miscellaneous Expenses	5,404,793	7,011,202
143	(589) Rents	98,518	133,676
144	TOTAL Operation (Enter Total of lines 134 thru 143)	7,538,446	9,693,907
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	724,542	743,196
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	41,604	74,336
149	(593) Maintenance of Overhead Lines	9,416,023	12,506,541
150	(594) Maintenance of Underground Lines	1,656,776	1,594,894
151	(595) Maintenance of Line Transformers		3,816
152	(596) Maintenance of Street Lighting and Signal Systems	32,914	43,468
153	(597) Maintenance of Meters	18,552	21,817
154	(598) Maintenance of Miscellaneous Distribution Plant	785,940	910,889
155	TOTAL Maintenance (Total of lines 146 thru 154)	12,676,351	15,898,957
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	20,214,797	25,592,864
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	547,348	538,860
161	(903) Customer Records and Collection Expenses	4,633,691	5,137,313
162	(904) Uncollectible Accounts	855,020	895,625
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,036,059	6,571,798

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	15,168,444	11,667,403
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	15,168,444	11,667,403
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	138,860	219,475
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	138,860	219,475
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	25,966,435	30,239,854
182	(921) Office Supplies and Expenses	4,627,467	4,373,997
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	10,830,723	10,216,545
185	(924) Property Insurance	6,071,680	4,492,896
186	(925) Injuries and Damages	-553,097	-206,879
187	(926) Employee Pensions and Benefits	1,819,104	1,691,303
188	(927) Franchise Requirements	21,534	21,037
189	(928) Regulatory Commission Expenses	3,431,544	3,812,938
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	312,343	393,158
192	(930.2) Miscellaneous General Expenses	2,426,894	21,129,045
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	54,954,627	76,163,894
195	Maintenance		
196	(935) Maintenance of General Plant	13,617,616	11,068,137
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	68,572,243	87,232,031
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	669,620,794	670,037,035

Schedule Page: 320 Line No.: 5 Column: b

Included with Account 501 are costs related to the sale of coal (from Minnesota Power's Boswell facility) to a retail customer for use in a non-rate base facility (See Rapids Energy Center on Page 403 to this FERC Form 1). In 2018, the cost of coal and related expenditures totaled $1,410,698. The corresponding revenue from this transaction is $2,161,303 and is reflected as part of account 456 - Other Electric Revenue at Page 300 to this FERC Form 1.

Schedule Page: 320 Line No.: 5 Column: c

Included with Account 501 are costs related to the sale of coal (from Minnesota Power's Boswell facility) to a retail customer for use in a non-rate base facility (See Rapids Energy Center on Page 403 to this FERC Form 1). In 2017, the cost of coal and related expenditures totaled $1,716,619. The corresponding revenue from this transaction is $2,460,451 and is reflected as part of account 456 - Other Electric Revenue at Page 300 to this FERC Form 1.

Schedule Page: 320 Line No.: 192 Column: b

See Page 335 of this FERC Form 1 for more information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Non-Associated Other Utilities	OS	134			
2						
3	Municipals	OS	134			
4						
5	Cooperatives					
6	Square Butte Electric Power	LU				
7	Other Cooperatives	OS	134			
8						
9	IPP / Non-Utilities	OS	134			
10	Power Marketers	OS	134			
11	Other Public Authorities	OS	134			
12	Utility	OS	134			
13	Foreign	OS	134			
14						
	Total					

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
295,100				10,477,443		10,477,443	1
							2
4,712			19,950	116,768		136,718	3
							4
							5
1,717,616			43,745,542	34,301,351		78,046,893	6
465,421			8,122,815	18,936,542		27,059,357	7
							8
160,004			70,000	4,371,870		4,441,870	9
1,100,800			109,375	35,447,400	19,300	35,576,075	10
2,353,496				81,246,309	-56,809	81,189,500	11
16				83,973		83,973	12
294,876			4,376,321	14,654,971	9,946	19,041,238	13
							14
6,392,041			56,444,003	199,636,627	-27,563	256,053,067	

Schedule Page: 326 Line No.: 1 Column: b

Other Services (OS) includes purchases of:

- Firm Power
- Economy Energy
- Replacement Energy
- Emergency Energy

Schedule Page: 326 Line No.: 6 Column: b

Rural Energy Agency Jurisdiction - Power Sales Interconnection Agreement between Square Butte Electric Cooperative and Minnesota Power (ALLETE, Inc.) (4/1/74). See Square Butte discussion in the Notes to Financial Statements on Page 123.

Schedule Page: 326 Line No.: 10 Column: l

Intercontinental Exchange broker fees.

Schedule Page: 326 Line No.: 11 Column: l

Multi-Value project transmission charges that are recoverable through transmission rider credit issued to customer.

Schedule Page: 326 Line No.: 12 Column: a

Utility includes purchases from Superior Water, Light and Power Company, a wholly owned subsidiary of ALLETE, Inc.

Schedule Page: 326 Line No.: 13 Column: l

Independent Electricity System Operator administrative expenses related to purchased energy.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	City of Wadena	Western Area Power Association	City of Wadena	OLF
2	City of Staples	Western Area Power Association	City of Staples	OLF
3	Great River Energy	Great River Energy	Great River Energy	FNO
4	WPPI Energy	N/A	N/A	OS
5	Midcontinent Independent System Operator	Various	Various	OS
6	Midcontinent Independent System Operator	Various	Minnesota Power	LFP
7	MISO - Schedule 26 Revenue	Various	N/A	OS
8	MISO - Schedule 37 Revenue	American Transmission Systems	N/A	OS
9	MISO - Schedule 38 Revenue	DEK / DEO	N/A	OS
10	MISO - Schedule 45 Revenue	Various	Various	OS
11				
12				
13				
14				
15				
16				
17				
18				
19				
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21				
22				
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24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
120	System	System		72,429	72,429	1
133	System	System		28,212	28,212	2
47, 48 & 49	System	System		2,498,864	2,419,084	3
N/A	N/A	N/A				4
OATT	System	System				5
173	HVDC West	HVDC East	550			6
OATT	System	System				7
OATT	System	System				8
OATT	System	System				9
OATT	System	System				10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			550	**2,599,505**	**2,519,725**	

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	493,313		493,313	1
	191,842		191,842	2
				3
		416,538	416,538	4
		4,741,537	4,741,537	5
		17,360,293	17,360,293	6
		24,599,806	24,599,806	7
		255,962	255,962	8
		319,490	319,490	9
		5,589,897	5,589,897	10
				11
				12
				13
				14
				15
				16
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				26
				27
				28
				29
				30
				31
				32
				33
				34
0	**685,155**	**53,283,523**	**53,968,678**	

Schedule Page: 328 Line No.: 3 Column: n

On May 6, 2016, FERC issued an order in dockets ER16-1107 and ER16-1108 accepting: (1) a Coordinated Local Planning Agreement, (2) Joint Pricing Zone Revenue Allocation Agreement, (3) a Revenue Credit Agreement for the Great Northern Transmission Line Project and (4) a Wholesale Distribution Service Agreement between Great River Energy and Minnesota Power. Together, the zonal agreements govern the respective obligations to each other concerning local transmission planning, cost allocation and revenue sharing for certain facilities and load within the Minnesota Power Pricing Zone. When the result of the Joint Pricing Zone Agreement is a payment from Great River Energy to Minnesota Power, revenue would be recorded on Page 328, Line 3. When the result of the Joint Pricing Agreement is a payment from Minnesota Power to Great River Energy, payment would be captured on Page 332, Line 7. Revenue received from the Wholesale Distribution Service Agreement is accounted for on Page 300, Line No. 21.

Schedule Page: 328 Line No.: 4 Column: m

Amount represents amortization of transmission delivery payment over the remaining life of Boswell Unit 4.

Schedule Page: 328 Line No.: 5 Column: m

Amount represents transmission service charge revenue generated under the Midcontinent Independent System Operator (MISO) Tariff.

Schedule Page: 328 Line No.: 6 Column: m

Amount represents transmission service charge revenue generated under the MISO High Voltage Direct Current Tariff.

Schedule Page: 328 Line No.: 7 Column: m

Minnesota Power participates in the MISO stakeholder-driven planning process referred to as the MISO Transmission Expansion Plan (MTEP). MISO has developed FERC-approved methodologies for allocating the cost of MTEP projects to all load-serving entities within the MISO footprint. There are currently three FERC-approved processes that allow MISO to allocate costs that are collected through Schedule 26, Schedule 26-A and Schedule 26-B to those who benefit from the project. Minnesota Power currently receives revenue under Schedule 26 for Baseline Reliability Projects that were approved in previous MTEP cycles.

Amount represents revenue Minnesota Power receives from other utilities as a result of the MISO Regional Expansion Criteria and Benefits cost allocation process.

Schedule Page: 328 Line No.: 8 Column: m

American Transmission Systems, Incorporated (ATSI) is responsible for a portion of MTEP Projects constructed or approved by the MISO Board of Directors for construction by MISO Transmission Owners. Minnesota Power receives revenue under Schedule 37 for Baseline Reliability Projects that were approved in MTEP cycles prior to June 1, 2011.

Amount represents revenue Minnesota Power receives from ATSI as a result of the MTEP cost allocation process.

Schedule Page: 328 Line No.: 9 Column: m

Duke Energy Kentucky, Inc. (DEK) and Duke Energy Ohio, Inc. (DEO) are responsible for a portion of MTEP Projects constructed or approved by the MISO Board of Directors for construction by MISO Transmission Owners. Minnesota Power receives revenue under Schedule 38 for Baseline Reliability Projects that were approved in MTEP cycles prior to June 1, 2011.

Amount represents revenue Minnesota Power receives from DEK and DEO as a result of the MTEP cost allocation process.

Schedule Page: 328 Line No.: 10 Column: m

MISO has developed a FERC-approved method for recovery of NERC Recommendation or Essential Action costs by NERC Transmission Owner Registered Entities through Schedule 45 of the MISO Tariff. Minnesota Power currently collects revenue for the October 7, 2010, NERC issued Recommendation to Industry for Consideration of Actual Field Conditions in Determination of Facility Ratings.

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Otter Tail Power	OS	754,094	754,094				
2								
3	Midcontinent	OS					65,104,601	65,104,601
4	Independent System							
5	Operator, Inc (MISO)							
6								
7	Great River Energy	FNS					2,800,000	2,800,000
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		754,094	754,094			67,904,601	67,904,601

Schedule Page: 332   Line No.: 3   Column: g

Amount represents transmission expense generated under the Midcontinent Independent System Operator Tariff.

Schedule Page: 332   Line No.: 7   Column: g

On May 6, 2016, FERC, issued an order in dockets ER16-1107 and ER16-1108 accepting: (1) a Coordinated Local Planning Agreement, (2) a Joint Zone Revenue Allocation Agreement, (3) a Revenue Credit Agreement for the Great Northern Transmission Line Project and (4) a Wholesale Distribution Service Agreement between Great River Energy and Minnesota Power. Together, the zonal agreements govern the respective obligations to each other concerning local transmission planning, cost allocation and revenue sharing for certain facilities and load within the Minnesota Power Pricing Zone.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Investor Relations Expense	764,786
7	Board of Directors Fees and Expenses	1,542,688
8	Deferred Fuel Adjustment Clause Activity	-69,000
9	External Reporting Expense	188,420
10		
11		
12		
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41		
42		
43		
44		
45		
46	TOTAL	2,426,894

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			4,887,383		4,887,383
2	Steam Production Plant	71,864,135	1,171,513			73,035,648
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	3,629,945				3,629,945
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	24,286,985	57,898			24,344,883
7	Transmission Plant	16,862,096				16,862,096
8	Distribution Plant	21,901,897				21,901,897
9	Regional Transmission and Market Operation					
10	General Plant	9,016,896				9,016,896
11	Common Plant-Electric					
12	TOTAL	147,561,954	1,229,411	4,887,383		153,678,748

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	2A Steam Prod. Plant						
14	311	189,249					
15	312	1,056,365					
16	314	147,544					
17	315	129,363					
18	316	9,720					
19	317	48,296					
20	SUBTOTAL	1,580,537					
21	2C Hydraulic Prod. Plt						
22	331	19,703					
23	332	129,217					
24	333	31,887					
25	334	20,364					
26	335	1,799					
27	336	436					
28	SUBTOTAL	203,406					
29	Other Production Plt						
30	341	52,617					
31	341	27					
32	344	732,703					
33	345	49,658					
34	346	3,221					
35	347	11,124					
36	SUBTOTAL	849,350					
37	3 Transmission Plant						
38	352	20,827	56.00	-10.00	2.07	R-5	
39	353	316,719	52.00	-20.00	2.27	R-3	
40	353	2,178	52.00		0.75	R-3	
41	354	26,053	63.00	-30.00	2.15	S-4	
42	355	274,212	63.00	-60.00	2.51	R-1.5	
43	356	98,148	62.00	-40.00	2.36	S-4	
44	356	23,380	71.00		1.38	S-6	
45	358	2,988	50.00		2.04	R-3	
46	359	59	60.00		1.64	R-3	
47	SUBTOTAL	764,564					
48	4 Distribution Plant						
49	361	11,673	60.00	-25.00	1.99	S-6	
50	362	91,157	49.00	-25.00	2.33	R-1	

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	362	1,365	49.00		1.76	R-1	
13	364	115,352	43.00	-75.00	4.81	S-6	
14	365	89,510	43.00	-55.00	4.22	S-6	
15	365	5,333	65.00		1.43	S-4	
16	366	12,313	68.00	-10.00	1.52	R-2	
17	367	103,014	48.00	-27.00	2.57	R-2	
18	368	93,026	44.00	-5.00	2.19	R-1.5	
19	369	6,165	40.00	-60.00	3.03	L-0	
20	369	12,242	42.00	-15.00	2.49	R-2	
21	370	64,316	20.00		6.48	S-6	
22	372	2,082	19.00	-50.00	5.45	R-3	
23	373	4,424	27.00	-50.00	4.75	L-0	
24	SUBTOTAL	611,972					
25	5 General Plant						
26	390	70,745					19.00
27	391	8,455	20.00	10.00	4.50	L-0.5	
28	391	14,064	7.00	5.00	13.57	S-3	
29	391	2,035	5.00	5.00	19.00	S-6	
30	392	2,554	25.00		4.00	R-4	
31	392	23	7.00		14.29	S-1.5	
32	392	1,946	8.00		12.50	L-2	
33	392	9,045	13.00		7.69	L-2	
34	393	1,299	20.00		5.00	R-1	
35	394	6,141	20.00	5.00	4.75	R-1	
36	395	3,684	20.00		5.00	S-4	
37	396	4,515	15.00		6.67	L-3	
38	397	19,812	15.00		6.67	R-1	
39	397	10,723	20.00		5.00	R-0.5	
40	397	5,979	10.00		10.00	R-0.5	
41	397	10,312	12.00		8.33	R-0.5	
42	397	4,803	10.00		10.00	R-0.5	
43	397	13,232	10.00		10.00	R-0.5	
44	397	16,105	25.00		4.00	S-6	
45	398	184	15.00	5.00	6.33		
46	398	11	10.00				
47	SUBTOTAL	205,667					
48							
49	TOTAL	4,215,496					
50							

Schedule Page: 336 Line No.: 13 Column: b

Steam Production and Hydraulic Production Plants are depreciated by average remaining life for each plant. Also Account 390 (Structure).

Schedule Page: 336 Line No.: 13 Column: g

Remaining Life by Facility	Years	Salvage Rate
Steam Production Plant		
Hibbard Renewable Energy Center - SE Station		
Unit No. 3	12.0	(2.11)%
Unit No. 4	12.0	(2.11)%
Laskin Energy Center - SE Station	13.0	(24.12)%
Boswell Energy Center - SE Station		
Unit No. 1	5.0	(16.08)%
Unit No. 2	5.0	(18.06)%
Unit No. 3	18.0	(7.92)%
Unit No. 4	18.0	(7.42)%
Common	18.0	(3.95)%
Taconite Harbor Energy Center - SE Station	9.0	(7.23)%
Cloquet Energy Center		
Other Production Plant		
Taconite Ridge 1 Wind	25.4	(0.31)%
Bison 1 Wind - Phase 1	27.9	(0.95)%
Bison 1 Wind - Phase 2	29.0	(0.93)%
Bison 2 Wind	30.0	(0.35)%
Bison 3 Wind	30.0	(0.42)%
Bison 4 Wind	32.0	0.03 %
Community Solar Gardens	23.9	
General Plant		
Structure & Improvements	19.0	

Remaining Life by Facility	Years
Hydraulic Production Plant	
Prairie River HE Station	46.0
Thomson HE Station	46.0
Fond du Lac HE Station	46.0
Winton HE Station	46.0
Knife Falls HE Station	46.0
Scanlon HE Station	46.0
Little Falls HE Station	46.0
Blanchard HE Station	46.0
Sylvan HE Station	46.0
Pillager HE Station	46.0
Birch Lake Reservoir	46.0
Boulder Lake Reservoir	46.0
Fish Lake Reservoir	46.0
Island Lake Reservoir	46.0
Rice Lake Reservoir	46.0
Whiteface Reservoir	46.0
Gauging Stations	46.0
White Iron Lake Reservoir	46.0

Schedule Page: 336 Line No.: 30 Column: a

Structures and Improvements, Wind

Schedule Page: 336 Line No.: 31 Column: a

Structures and Improvements, Solar

Schedule Page: 336 Line No.: 39 Column: a

Station Equipment

Schedule Page: 336 Line No.: 40 Column: a

Station Equipment - Reserve Equipment

Schedule Page: 336 Line No.: 43 Column: a

Overhead Conductors & Devices

Schedule Page: 336 Line No.: 44 Column: a

Clearing Land and Right-of-Way

Schedule Page: 336 Line No.: 50 Column: a

Station Equipment

Schedule Page: 336.1 Line No.: 12 Column: a

Station Equipment - Reserve Equipment

Schedule Page: 336.1 Line No.: 14 Column: a

Overhead Conductors and Devices

Schedule Page: 336.1 Line No.: 15 Column: a

Clearing Land & Right-of-Way

Schedule Page: 336.1 Line No.: 19 Column: a

Services - Overhead

Schedule Page: 336.1 Line No.: 20 Column: a

Services - Underground

Schedule Page: 336.1 Line No.: 27 Column: a

Office Furniture and Equipment

Schedule Page: 336.1 Line No.: 28 Column: a

Office Furniture and Equipment - Computers

Schedule Page: 336.1 Line No.: 29 Column: a

Office Furniture and Equipment - Personal Computer Program

Schedule Page: 336.1 Line No.: 30 Column: a

Transportation Equipment - Trailers

Schedule Page: 336.1 Line No.: 31 Column: a

Transportation Equipment Vehicle Class 1 - Automobiles

Schedule Page: 336.1 Line No.: 32 Column: a

Transportation Equipment Vehicle Class 3 - Large Trucks with Mounted Power Equipment

Schedule Page: 336.1 Line No.: 33 Column: a

Transportation Equipment Vehicle Class 6 - Heavy Trucks

Schedule Page: 336.1 Line No.: 38 Column: a

Communication Equipment - General

Schedule Page: 336.1 Line No.: 39 Column: a

Communication Equipment - Microwave

Schedule Page: 336.1 Line No.: 40 Column: a

Telephone & Communication Equipment - Phone and Fiber Optic

Schedule Page: 336.1 Line No.: 41 Column: a

Communication Equipment - Mobile Radio

Schedule Page: 336.1 Line No.: 42 Column: a

Communication Equipment - Data Communication

Schedule Page: 336.1 Line No.: 43 Column: a

Communication Equip - Fiber Optic System

Schedule Page: 336.1 Line No.: 44 Column: a

Communication Equipment - Fiber Optic Cable

Schedule Page: 336.1 Line No.: 45 Column: a

Miscellaneous Equipment, 15 Year

Schedule Page: 336.1 Line No.: 46 Column: a

Miscellaneous Equipment, 10 Year

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FERC Annual Assessments & Fees	1,233,868		1,233,868	
2	(Includes any assessments through MISO)				
3					
4	MN Department of Commerce Assessments & Fees	1,084,474		1,084,474	
5					
6	Regulatory Expense Related to Hydro Operations	354,152		354,152	
7	(Includes licenses, insurance, misc.)				
8					
9	2016 Retail Rate Case Additional Misc. Expense		759,050	759,050	
10	(MPUC Docket No. E-015/GR-16-664)				
11					
12					
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15					
16					
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45					
46	TOTAL	2,672,494	759,050	3,431,544	

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REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	1,233,868					1
							2
							3
	928	1,084,474					4
							5
	928	354,152					6
							7
							8
	928	759,050					9
							10
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		3,431,544					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute Membership
2		
3	B(5)	Total
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
	157,140	920	157,140		1
					2
	157,140		157,140		3
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DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	16,465,173		
4	Transmission	6,236,010		
5	Regional Market			
6	Distribution	5,724,612		
7	Customer Accounts	2,674,759		
8	Customer Service and Informational	1,414,126		
9	Sales	21,129		
10	Administrative and General	22,745,544		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	55,281,353		
12	Maintenance			
13	Production	9,752,900		
14	Transmission	3,174,059		
15	Regional Market			
16	Distribution	5,435,034		
17	Administrative and General	5,175,353		
18	TOTAL Maintenance (Total of lines 13 thru 17)	23,537,346		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,218,073		
21	Transmission (Enter Total of lines 4 and 14)	9,410,069		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,159,646		
24	Customer Accounts (Transcribe from line 7)	2,674,759		
25	Customer Service and Informational (Transcribe from line 8)	1,414,126		
26	Sales (Transcribe from line 9)	21,129		
27	Administrative and General (Enter Total of lines 10 and 17)	27,920,897		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	78,818,699	1,010,548	79,829,247
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	78,818,699	1,010,548	79,829,247
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	15,758,408	1,027,871	16,786,279
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	15,758,408	1,027,871	16,786,279
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,614,595	116,852	1,731,447
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,614,595	116,852	1,731,447
77	Other Accounts (Specify, provide details in footnote):			
78	Billable Services - WPPI (Boswell Unit #4)	1,749,614		1,749,614
79	Billable Services - Other, Subsidiary Billings, Misc.	10,249,029	-2,155,271	8,093,758
80	Non-Utility Activity	5,993,667		5,993,667
81				
82				
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95	TOTAL Other Accounts	17,992,310	-2,155,271	15,837,039
96	TOTAL SALARIES AND WAGES	114,184,012		114,184,012

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ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	19,012,133	36,837,998	59,378,070	81,658,478
3	Net Sales (Account 447)	(5,102,201)	(9,280,249)	(11,960,726)	(15,897,035)
4	Transmission Rights	122,253	(243,991)	(631,683)	(705,065)
5	Ancillary Services	152,328	231,043	163,432	143,296
6	Other Items (list separately)				
7	Real Time Mult Value Projects Distr	(31,280)	(46,676)	(54,352)	(56,809)
8	Resource Adequacy Auction	46	(5,704)	(28,704)	(51,704)
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46	TOTAL	14,153,279	27,492,421	46,866,037	65,091,161

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		MWh	444,188			
2	Reactive Supply and Voltage		MWh	1,680,960		varies	1,844,450
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)			2,125,148			1,844,450

Schedule Page: 398   Line No.: 1   Column: b

The total number of units purchased under Schedules 1 and 2 was 15,000 MWh in 2018.

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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	1,550	5	18	1,499	35		16		
2	February	1,545	1	8	1,492	36		17		
3	March	1,474	27	11	1,429	32		13		
4	Total for Quarter 1				4,420	103		46		
5	April	1,489	6	9	1,443	31		15		
6	May	1,493	25	14	1,445	34		14		
7	June	1,541	29	16	1,494	31		16		
8	Total for Quarter 2				4,382	96		45		
9	July	1,506	31	17	1,491			15		
10	August	1,605	13	15	1,589			16		
11	September	1,464	14	16	1,452			12		
12	Total for Quarter 3				4,532			43		
13	October	1,444	15	8	1,431			13		
14	November	1,562	28	13	1,547			15		
15	December	1,537	31	18	1,522			15		
16	Total for Quarter 4				4,500			43		
17	Total Year to Date/Year				17,834	199		177		

Schedule Page: 400 Line No.: 1 Column: f

Firm Network Service for Others. The following megawatt loads of Great River Energy and Xcel Energy are in the Minnesota Power Midcontinent Independent System Operator Pricing Zone; however, these loads are excluded from Firm Network Service for Others in column (f) as these loads are reported by each respective company:

Megawatt Load	Great River Energy	Xcel Energy
January	180	21
February	242	20
March	141	14
April	194	17
May	154	15
June	159	20
July	174	17
August	187	20
September	125	15
October	167	14
November	169	17
December	212	19

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ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	9,027,899
3	Steam	6,467,073			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	1,610,792
5	Hydro-Conventional	607,664			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,952,562
7	Other	1,563,688			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	8,638,425	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	18,137
10	Purchases	6,392,041	27	Total Energy Losses	500,856
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	15,110,246
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	2,599,505			
17	Delivered	2,519,725			
18	Net Transmission for Other (Line 16 minus line 17)	79,780			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	15,110,246			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,376,159	370,479	1,534	5	18
30	February	1,239,992	320,103	1,528	1	8
31	March	1,274,957	312,056	1,461	27	11
32	April	1,232,924	335,780	1,474	6	9
33	May	1,242,622	356,137	1,479	25	14
34	June	1,186,648	313,054	1,525	29	16
35	July	1,247,284	318,390	1,491	31	17
36	August	1,236,665	327,600	1,589	13	15
37	September	1,193,546	322,282	1,452	14	16
38	October	1,221,104	305,272	1,431	15	8
39	November	1,270,825	328,953	1,547	28	13
40	December	1,307,740	342,456	1,522	31	18
41	TOTAL	15,030,466	3,952,562			

Schedule Page: 401 Line No.: 29 Column: b

Had customer-provided generation (Coincident Customer Net Generation Load (CCNL)) been included in 'Total Monthly Energy', the monthly totals for Column b, Page 401b and system peaks would have been:

Month	Col. b	CCNL (excludes MP Regulated Purchases)	Combined Total	CCNL Inclusive Peak
January	1,376,159	111,705	1,487,864	1,737
February	1,239,992	98,323	1,338,315	1,718
March	1,274,957	103,735	1,378,692	1,613
April	1,232,924	96,940	1,329,864	1,627
May	1,242,622	102,851	1,345,473	1,615
June	1,186,648	98,726	1,285,374	1,666
July	1,247,284	117,520	1,364,804	1,636
August	1,236,665	99,791	1,336,456	1,728
September	1,193,546	86,318	1,279,864	1,588
October	1,221,104	107,216	1,328,320	1,582
November	1,270,825	104,671	1,375,496	1,698
December	1,307,740	108,480	1,416,220	1,684
TOTAL	**15,030,466**	**1,236,276**	**16,266,742**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Boswell (b)	Plant Name: Laskin (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam Turbine	Steam Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Convntl. Outdoor Blr	Outdoor Boiler
3	Year Originally Constructed	1958	1953
4	Year Last Unit was Installed	1980	1953
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	960.00	116.00
6	Net Peak Demand on Plant - MW (60 minutes)	945	66
7	Plant Hours Connected to Load	8760	8760
8	Net Continuous Plant Capability (Megawatts)	950	98
9	When Not Limited by Condenser Water	950	98
10	When Limited by Condenser Water	950	98
11	Average Number of Employees	184	12
12	Net Generation, Exclusive of Plant Use - KWh	6442894077	13892991
13	Cost of Plant: Land and Land Rights	10103855	253164
14	Structures and Improvements	155562164	11215690
15	Equipment Costs	1066639333	63507824
16	Asset Retirement Costs	22718859	11196718
17	Total Cost	1255024211	86173396
18	Cost per KW of Installed Capacity (line 17/5) Including	1307.3169	742.8741
19	Production Expenses: Oper, Supv, & Engr	5172880	323775
20	Fuel	148124946	928785
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	6870308	1168324
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1661183	0
26	Misc Steam (or Nuclear) Power Expenses	381442	157451
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	2698042	142273
30	Maintenance of Structures	829051	50490
31	Maintenance of Boiler (or reactor) Plant	8366225	145998
32	Maintenance of Electric Plant	1905659	144445
33	Maintenance of Misc Steam (or Nuclear) Plant	3314779	136977
34	Total Production Expenses	179324515	3198518
35	Expenses per Net KWh	0.0278	0.2302

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal (SB)	Natural Gas		Natural Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	MCF		MCF		
38	Quantity (Units) of Fuel Burned	3796387	95536	0	231097	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9016	1	0	1	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.100	3.440	0.000	3.750	0.000	0.000
41	Average Cost of Fuel per Unit Burned	36.880	3.440	0.000	3.750	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.050	3.340	0.000	3.540	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.022	0.000	0.000	0.062	0.000	0.000
44	Average BTU per KWh Net Generation	10626.000	0.000	0.000	17632.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Hibbard* (d)	Plant Name: *Rapids Non Rate-base* (e)	Plant Name: *Taconite Harbor* (f)	Line No.
Steam Turbine	Steam Turbine	Steam Turbine	1
Conventional	Conventional, Indoor	Conventional Boiler	2
1931	1969	1957	3
1951	1980	1967	4
72.00	29.00	169.00	5
42	24	0	6
8760	0	0	7
60	23	137	8
60	23	137	9
60	23	137	10
31	30	5	11
10285430	0	0	12
87760	0	143350	13
7951601	3200832	16783431	14
88122490	25720437	125179637	15
3945153	0	10435438	16
100107004	28921269	152541856	17
1390.3751	997.2851	902.6145	18
415154	0	146341	19
588306	0	42960	20
0	0	0	21
2459873	0	64154	22
0	0	0	23
0	0	0	24
7671	0	153951	25
235047	0	26675	26
0	0	0	27
0	0	0	28
429687	0	87687	29
107591	0	31409	30
1044000	0	56926	31
652012	0	11189	32
396803	0	18530	33
6336144	0	639822	34
0.6160	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Wood Waste	Natural Gas								36
Tons	MCF								37
15011	4076	0	0	0	0	0	0	0	38
4676	1	0	0	0	0	0	0	0	39
23.910	4.350	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
23.910	4.350	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
2.560	4.260	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
14054.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

In September 1990, 20 percent of Boswell Unit 4 was sold to Wisconsin Public Power Systems, Inc. ALLETE, Inc. is the operating agent for the entire unit. Amounts listed for the Boswell station reflect only ALLETE, Inc.'s portion of ownership.

In December 2018, ALLETE, Inc. retired Boswell Units 1 and 2.

Schedule Page: 403 Line No.: -1 Column: e

The Rapids Energy Center facility was purchased in 2000 from a retail customer. ALLETE, Inc. operates this facility for the exclusive energy needs of that customer as a non-rate base operation. All revenue and expenses associated with this facility appear as part of FERC Accounts 417 and 417.1. Energy produced at this facility is not included in retail sales or included in generation figures listed elsewhere in this FERC From 1.

Schedule Page: 403 Line No.: -1 Column: f

In 2001, Minnesota Power acquired this generation facility through its wholly owned subsidiary Rainy River Energy Corporation - Taconite Harbor (RRTH). In 2002, ownership of this facility and associated assets were transferred from RRTH to ALLETE, Inc. via a statutory merger under Minnesota law. The disposition of jurisdictional facilities and the underlying merger were approved by the FERC on January 23, 2002 (98 FERC 62,034 - Docket No. EC02-16-000 and EC02-16-001) and by the Minnesota Public Utilities Commission in orders dated May 22, 2002 (Docket No. E015/AI-01-1648), June 11, 2002 (Docket No. E015/AI-01-1988) and an order dated September 17, 2002, that approved a compliance filing for the two referenced dockets. Non-rate base operations at the generating facility began in 2002.

In October 2005, in conjunction with the Company's Integrated Resource Plan, Minnesota Power proposed to the Minnesota Public Utilities Commission (MPUC) a comprehensive solution to meet generation needs through 2010 that included a transition of the Taconite Harbor generating facility from non-rate base energy operations to regulated utility to help meet the utility's forecasted base load energy requirements. The proposal to transition Taconite Harbor to a regulated utility asset was supported by the Minnesota Department of Commerce (DOC) and a group of Large Power Customers. On April 6, 2006, the MPUC approved the Integrated Resource Plan, including the transfer of Taconite Harbor at book value to regulated utility operations effective January 1, 2006.

Schedule Page: 403 Line No.: 5 Column: d

M. L. Hibbard station steam turbines 1 and 2 remain in cold lay-up status. In 1987, boiler units 3 and 4 were sold to the City of Duluth, Minnesota and converted to utilize coal and wood fuel to provide the steam supply for Duluth Steam District #2, part of which was then repurchased as "Steam from Other Sources." ALLETE, Inc. employees operated Duluth Steam District #2 for the City of Duluth, Minnesota. Unit 3 and 4 turbines were placed back in service in 1996 and 1998, respectively.

On September 30, 2009, ALLETE, Inc. purchased all of the assets of the Duluth Steam District #2 from the City of Duluth, Minnesota; primarily unit 3 and 4 boilers, fuel handling and pollution control equipment. ALLETE, Inc. owns and operates all processes of the steam electric station. ALLETE, Inc. also sells available steam to a retail customer for use in their paper-making plant with revenue being recorded in Account 456.

Schedule Page: 402 Line No.: 17 Column: b

In December 2018, ALLETE, Inc. retired Boswell Units 1 and 2. Total cost amounts listed for the Boswell station reflect only the remaining costs for Boswell Units 3 and 4.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2360 Plant Name: Thomson (b)	FERC Licensed Project No. 346 Plant Name: Blanchard (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1907	1925
4	Year Last Unit was Installed	1949	1988
5	Total installed cap (Gen name plate Rating in MW)	72.60	18.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	74	16
7	Plant Hours Connect to Load	8,760	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	74	16
10	(b) Under the Most Adverse Oper Conditions	62	7
11	Average Number of Employees	21	0
12	Net Generation, Exclusive of Plant Use - Kwh	355,802,450	101,216,730
13	Cost of Plant		
14	Land and Land Rights	332,844	134,457
15	Structures and Improvements	8,420,393	3,091,618
16	Reservoirs, Dams, and Waterways	74,797,786	4,663,964
17	Equipment Costs	28,504,104	6,246,929
18	Roads, Railroads, and Bridges	90,090	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	112,145,217	14,136,968
21	Cost per KW of Installed Capacity (line 20 / 5)	1,544.7000	785.3871
22	Production Expenses		
23	Operation Supervision and Engineering	481,593	103,327
24	Water for Power	0	0
25	Hydraulic Expenses	535,537	132,778
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	61,576	2,864
28	Rents	0	0
29	Maintenance Supervision and Engineering	256,615	42,044
30	Maintenance of Structures	16,824	0
31	Maintenance of Reservoirs, Dams, and Waterways	588,931	58,457
32	Maintenance of Electric Plant	319,363	152,789
33	Maintenance of Misc Hydraulic Plant	636,757	70,140
34	Total Production Expenses (total 23 thru 33)	2,897,196	562,399
35	Expenses per net KWh	0.0081	0.0056

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2360 Plant Name: Fond Du Lac (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage			1
Conventional			2
1924			3
1924			4
11.00	0.00	0.00	5
13	0	0	6
8,760	0	0	7
			8
13	0	0	9
13	0	0	10
0	0	0	11
50,598,130	0	0	12
			13
874,754	0	0	14
853,326	0	0	15
10,809,970	0	0	16
6,344,295	0	0	17
309,483	0	0	18
0	0	0	19
19,191,828	0	0	20
1,744.7116	0.0000	0.0000	21
			22
72,969	0	0	23
0	0	0	24
95,398	0	0	25
0	0	0	26
6,387	0	0	27
0	0	0	28
25,694	0	0	29
53,177	0	0	30
289,815	0	0	31
120,364	0	0	32
51,005	0	0	33
714,809	0	0	34
0.0141	0.0000	0.0000	35

Schedule Page: 406 Line No.: 11 Column: b

There are 21 employees stationed at Thomson. These employees support Thomson, Fond du Lac and various other stations.

Schedule Page: 406 Line No.: 11 Column: c

There are no employees stationed at Blanchard; however, the 6 employees stationed at Little Falls support Blanchard and various other stations.

Schedule Page: 406 Line No.: 11 Column: d

There are no employees stationed at Fond du Lac; however, the 21 employees stationed at Thomson support Fond du Lac and various other stations.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDRO PLANTS					
2						
3	Knife Falls FERC Project No. 2360	1922	2.40	2.2	12,007,855	4,562,386
4						
5	Little Falls FERC Project No. 2532	1906	4.60	4.9	32,656,350	13,766,283
6						
7	Pillager FERC Project No. 2663	1917	1.50	1.7	10,342,940	2,424,910
8						
9	Prairie River FERC Project No. 2361	1920	1.10	0.9	3,239,400	4,665,691
10						
11	Scanlon FERC Project No. 2360	1923	1.60	1.7	8,873,609	3,751,673
12						
13	Sylvan FERC Project No. 2454	1913	1.80	1.9	11,200,800	2,372,618
14						
15	Winton FERC Project No. 469	1923	4.00	4.2	21,725,690	5,895,713
16						
17	Rapids FERC Proj. No. 2362 (non-rate base)	1917	2.10			3,150,418
18						
19	Other Hydro Assets (Resvr., Strm Gages, etc.)					24,612,861
20						
21	SOLAR PLANT					
22						
23	Camp Ripley Solar Array	2016	10.00	11.0	16,678,300	15,174,637
24						
25	WIND TURBINE PLANTS					
26						
27	Taconite Ridge Energy Center	2008	25.00	25.0	50,813,000	48,803,698
28						
29	Bison Wind Energy Center	2014	497.00	496.2	1,496,131,220	786,853,980
30						
31						
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Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
1,900,994	35,018		282,918	Hydro		3
						4
2,928,996	61,919		488,130	Hydro		5
						6
1,347,172	19,914		121,253	Hydro		7
						8
4,241,537	14,604		77,592	Hydro		9
						10
2,344,796	23,345		109,767	Hydro		11
						12
1,318,121	23,897		102,777	Hydro		13
						14
1,473,928	53,104		159,413	Hydro		15
						16
1,500,199				Hydro		17
						18
						19
						20
						21
						22
1,517,464			201,950	Solar		23
						24
						25
						26
1,952,148	539,985		822,959	Wind		27
						28
1,583,207	4,640,246		10,432,328	Wind		29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Schedule Page: 410   Line No.: 17   Column: a

The Rapids Energy Center facility was purchased in 2000 from a retail customer. ALLETE, Inc. operates this facility for the exclusive energy needs of that customer as a non-rate base facility. All revenue and expenses associated with this facility appear as part of Accounts 417 and 417.1. Energy produced at this facility is not included in retail sales or generation figures listed elsewhere in this FERC Form 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Kettle River	Denham	500.00	500.00	Steel Tower	7.78		1
2								
3	Monticello	Quarry	345.00	345.00	Steel Pole	28.77		1
4	Quarry	Alexandria	345.00	345.00	Steel Pole	77.45		1
5	Alexandria	ND Border	345.00	345.00	Steel Pole	101.21		1
6	ND Border	Fargo	345.00	345.00	Steel Pole	34.44		1
7								
8	Square Butte (MN Portion)	Arrowhead DC Line	250.00	250.00	Steel Tower	231.43		1
9	Square Butte (ND Portion)	Arrowhead DC Line	250.00	250.00	Steel Tower	233.91		1
10								
11	Calumet	McCarthy Lake	230.00	230.00	H-Frame-Wd	3.31		1
12	Boswell	Calumet	230.00	230.00	H-Frame-Wd	25.85		1
13	Tri-County	Bison	230.00	230.00	H-Frame-Wd	10.96		1
14	Forbes	Minntac	230.00	230.00	H-Frame-Wd	25.50	0.55	1
15	Bison	Square Butte	230.00	230.00	H-Frame-Wd	22.05		1
16	Zemple	Cass Lake	230.00	230.00	H-Frame-Steel	51.08		1
17	Boswell	Blackberry	230.00	230.00	H-Frame-Wd	18.41	0.29	1
18	Bear Creek	Kettle River	230.00	230.00	H-Frame-Wd	11.79		1
19	Hubbard	Shell River	230.00	230.00	H-Frame-Wd	4.53		1
20	Riverton	Staples	230.00	230.00	H-Frame-Wd	35.96		1
21	Cass Lake	Winton	230.00	230.00	H-Frame-Steel	19.32		1
22	Arrowhead	Forbes	230.00	230.00	H-Frame-Wd	47.48		1
23	Riverton	Badoura	230.00	230.00	H-Frame-Wd	46.41		1
24	Riverton	Blackberry	230.00	230.00	H-Frame-Wd	67.18		1
25	Iron Range	Forbes	230.00	230.00	H-Frame-Wd	34.33		1
26	McCarthy Lake	Shannon	230.00	230.00	H-Frame-Wd	16.39		1
27	Boswell	Blackberry	230.00	230.00	H-Frame-Wd	18.80	2.40	1
28	Shannon	Minntac	230.00	230.00	H-Frame-Wd	23.11	0.55	1
29	Shannon	Littlefork	230.00	230.00	H-Frame-Wd	89.09		1
30	Arrowhead	Iron Range	230.00	230.00	H-Frame-Wd	71.90		1
31	Badoura	Hubbard	230.00	230.00	H-Frame-Wd	14.98		1
32	Arrowhead	Bear Creek	230.00	230.00	H-Frame-Wd	55.22		1
33								
34	Taconite Harbor	Dunka Road	138.00	138.00	Steel Tower	61.21		1
35	Taconite Harbor	Erie	138.00	138.00	Steel Tower	61.20	60.00	1
36					TOTAL	2,766.37	97.06	124

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Laskin	Erie	138.00	138.00	H-Frame-Wd	7.96		1
2								
3	Various		115.00	115.00	H-Frame-Wd	4.36		1
4	Various		115.00	115.00	Steel Pole	0.11		1
5	Various		115.00	115.00	H-Frame-Wd	18.41		5
6	Various		115.00	115.00	H-Frame-Wd	1.88		2
7	Various		115.00	115.00	H-Frame-Wd	358.40	0.96	20
8	Various		115.00	115.00	H-Frame-Wd	342.05	3.14	13
9	Various		115.00	115.00	H-Frame-Wd	449.55	17.45	39
10	Various		115.00	115.00	H-Frame-Wd	15.54	2.96	4
11	Various		115.00	115.00	Steel Pole	15.39	8.76	3
12	Various		115.00	115.00	Steel Pole	1.47		3
13								
14	UPA	Hinckley	69.00	69.00	Sgl Pole-Wd	0.20		1
15								
16								
17								
18								
19								
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21								
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32								
33								
34								
35								
36					TOTAL	2,766.37	97.06	124

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
3-1192 ACSR	462,475	1,865,069	2,327,544					1
								2
2-954 ACSS	2,469,851	10,319,920	12,789,771					3
2-954 ACSS		36,650,276	36,650,276					4
2-954 ACSS		36,729,631	36,729,631					5
2-954 ACSS		14,643,844	14,643,844					6
								7
2839 ACSR	1,262,966	18,352,781	19,615,747					8
2839 ACSR	1,375,820	29,828,682	31,204,502					9
								10
1590 ACSR	401,330	2,181,918	2,583,248					11
1590 ACSR	5,608,253	10,810,652	16,418,905					12
1780 ACSS	921,495	6,961,917	7,883,412					13
954 ACSR	629,523	3,399,250	4,028,773					14
1780 ACSR		11,567,318	11,567,318					15
795 ACSS	633,134	6,510,636	7,143,770					16
1590 ACSR	598,861	3,712,937	4,311,798					17
795 ACSR	48,642	664,749	713,391					18
795 ACSR	26,459	226,517	252,976					19
795 ACSR	160,242	1,528,175	1,688,417					20
795 ACSS	547,027	2,439,336	2,986,363					21
1033 ACSS/TW	316,097	5,033,292	5,349,389					22
795 ACSR	269,952	1,948,224	2,218,176					23
795 ACSR	403,973	7,232,077	7,636,050					24
954 ACSR	383,227	2,649,627	3,032,854					25
1590 ACSR	2,072,422	5,656,642	7,729,064					26
1431 ACSR	258,330	3,594,748	3,853,078					27
954 ACSR	212,856	2,310,142	2,522,998					28
954 ACSR	1,410,952	11,404,912	12,815,864					29
954 ACSR	985,091	9,645,841	10,630,932					30
795 ACSR	69,673	619,639	689,312					31
795 ACSR	223,667	1,978,794	2,202,461					32
								33
477ACSR	119,285	2,444,496	2,563,781					34
477 ACSR		406,339	406,339					35
	37,147,555	402,305,482	439,453,037					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
636 ACSR	105,246	1,955,426	2,060,672					1
								2
795 ACSR	13,432	1,231,853	1,245,285					3
336 ACSR		409,275	409,275					4
1272 ACSR	194,855	2,192,956	2,387,811					5
1590 ACSR	17,731	1,161,073	1,178,804					6
336 ACSR	1,567,250	26,093,147	27,660,397					7
4/0 CU	1,885,208	37,408,886	39,294,094					8
636 ACSR	10,900,189	73,556,985	84,457,174					9
954 ACSR	363,401	1,768,190	2,131,591					10
636 ACSR	228,640	2,764,297	2,992,937					11
795 ACSR		397,119	397,119					12
								13
336 ACSR		47,894	47,894					14
								15
								16
								17
								18
								19
								20
								21
								22
								23
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								29
								30
								31
								32
								33
								34
								35
	37,147,555	402,305,482	439,453,037					36

Schedule Page: 422   Line No.: 1   Column: a

Transmission Line #601

Schedule Page: 422   Line No.: 3   Column: a

Transmission Line #973

Schedule Page: 422   Line No.: 4   Column: a

Transmission Line #954

Schedule Page: 422   Line No.: 5   Column: a

Transmission Line #955 MN Portion

Schedule Page: 422   Line No.: 6   Column: a

Transmission Line #955 ND Portion

Schedule Page: 422   Line No.: 8   Column: a

Square Butte to Arrowhead DC Line is located in North Dakota and Minnesota.

Line 8 is the Minnesota portion (North Dakota / Minnesota border to Arrowhead DC Line).

Schedule Page: 422   Line No.: 9   Column: a

Square Butte to Arrowhead DC Line is located in North Dakota and Minnesota.

Line 9 is the North Dakota portion (Square Butte to North Dakota / Minnesota border).

Schedule Page: 422.1   Line No.: 3   Column: a

Includes the following 1 transmission line: 05.

Schedule Page: 422.1   Line No.: 4   Column: a

Includes the following 1 transmission line: 157.

Schedule Page: 422.1   Line No.: 5   Column: a

Includes the following 5 transmission lines: 60, 64, 67, 68, 69.

Schedule Page: 422.1   Line No.: 6   Column: a

Includes the following 2 transmission lines: 50, 54.

Schedule Page: 422.1   Line No.: 7   Column: a

Includes the following 20 transmission lines: 13, 24, 26, 39, 40, 41, 42, 44, 47, 48, 51, 130, 133, 138, 146, 151, 155, 725, 867, 868.

Schedule Page: 422.1   Line No.: 8   Column: a

Name of Respondent ALLETE, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2018/Q4

FOOTNOTE DATA

Includes the following 13 transmission lines: 8, 9, 10, 11, 12, 16, 17, 25, 34, 46, 49, 135, 137.

Schedule Page: 422.1 Line No.: 9 Column: a

Includes the following 39 transmission lines: 6,14,15,18,19, 20, 22, 27, 28, 29, 35, 36, 37, 38, 45, 52, 53, 55, 56, 57, 58, 61, 62, 63, 70, 72, 74, 76, 78, 79, 126, 128, 134, 142, 145, 147, 153, 159, 726.

Schedule Page: 422.1 Line No.: 10 Column: a

Includes the following 4 transmission lines: 7, 77, 131, 132.

Schedule Page: 422.1 Line No.: 11 Column: a

Includes the following 3 transmission lines: 21,66, 71.

Schedule Page: 422.1 Line No.: 12 Column: a

Includes the following 2 transmission lines: 136,152

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Blackwater Lake	Boswell	0.28	Steel Pole	14.29	1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.28		14.29	1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
636	ACSR		115		563,358			563,358	1
									2
									3
									4
									5
									6
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					563,358			563,358	44

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	0 Subs under 10 MVA, MN	Dist-Unattended	7.00		
2	2 Subs under 10 MVA, MN	Dist-Unattended	14.00		
3	9 Subs under 10 MVA, MN	Dist-Unattended	23.00		
4	43 Subs under 10 MVA, MN	Dist-Unattended	34.00		
5	11 Subs under 10 MVA, MN	Dist-Unattended	46.00		
6	6 Subs under 10 MVA, MN	Dist-Unattended	115.00		
7	15th Avenue West-Duluth, MN	Dist-Unattended	115.00	14.00	
8	Arrowhead-Adolph, MN	Trans-Unattended	230.00	115.00	
9	Akeley-Akeley, MN	Dist-Unattended	115.00	34.00	
10	Babbitt-Babbit, MN	Trans-Unattended	115.00	46.00	
11	Badoura-Badoura, MN	Trans-Unattended	230.00	115.00	
12	Badoura-Badoura, MN	Dist-Unattended	115.00	34.00	
13	Baxter-Brainerd, MN	Dist-Unattended	115.00	34.00	
14	Bison 1,2,3,4-New Salem, ND	Trans-Unattended	230.00		
15	Blackberry-Blackberry, MN	Trans-Unattended	230.00	115.00	
16	Blanchard HE-North Little Falls, MN	Dist-Attended	115.00	34.00	
17	Brainerd-Brainerd, MN	Dist-Unattended	115.00	34.00	
18	Calumet-Nashwauk, MN	Trans-Unattended	230.00	14.00	
19	Canosia Road-Cloquet,MN	Dist-Unattended	115.00	14.00	
20	Center, ND-Sq.Butte	Trans-Unattended	230.00		
21	Clay Boswell-Cohasset, MN	Trans-Attended	115.00	23.00	
22	Cloquet-Cloquet, MN	Dist-Unattended	115.00	14.00	
23	Colbyville-Duluth, MN	Dist-Unattended	115.00	14.00	
24	Dog Lake-North Brainerd, MN	Dist-Unattended	115.00	34.00	
25	Eagle Valley-Eagle Bend, MN	Dist-Unattended	115.00	34.00	
26	Embarrass-Embarrass, MN	Trans-Unattended	115.00	115.00	
27	Embarrass-Embarrass, MN	Dist-Unattended	115.00	23.00	
28	Forbes-Forbes, MN	Trans-Unattended	500.00	230.00	
29	Forbes-Forbes, MN	Trans-Unattended	230.00	115.00	
30	Four Corners-Duluth,MN	Dist-Unattended	115.00	14.00	
31	French River,MN	Dist-Unattended	115.00	14.00	
32	Gary-Duluth, MN	Dist-Unattended	115.00	14.00	
33	Grand Rapids-Grand Rapids, MN	Dist-Unattended	115.00	23.00	
34	Haines Road-Duluth, MN	Dist-Unattended	115.00	14.00	
35	Hat trick-Eveleth	Dist-Unattended	115.00	23.00	
36	Hewitt-Hewitt, MN	Dist-Unattended	7.00	2.00	
37	Hibbing-Hibbing, MN	Dist-Unattended	115.00	23.00	
38	Hilltop-Duluth, MN	Trans-Unattended	230.00	115.00	
39	Hinckley East-Hinckley, MN	Dist-Unattended	46.00	12.00	
40	Hinckley East-Hinckley, MN	Dist-Unattended	69.00	46.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	International Falls, MN	Dist-Unattended	115.00	14.00	
2	International Falls, MN	Trans-Unattended	115.00	115.00	
3	Lake Superior Paper, Inc. - Duluth, MN	Dist-Unattended	115.00	14.00	
4	Lake Superior Paper, Inc. - Duluth, MN	Dist-Unattended	115.00	34.00	
5	Lind Greenway	Dist-Unattended	115.00	23.00	
6	Little Falls-Little Falls, MN	Dist-Unattended	115.00	34.00	
7	Little Fork-Little Fork, MN	Trans-Unattended	230.00	115.00	
8	Long Prairie - Long Prairie, MN	Dist-Unattended	115.00	34.00	
9	M.L. Hibbard-Duluth, MN	Dist-Attended	115.00	14.00	
10	Mahtowa-Mahtowa, MN	Dist-Unattended	115.00	23.00	
11	Mahtowa-Mahtowa, MN	Dist-Unattended	115.00	46.00	
12	Maturi	Dist-Unattended	115.00	23.00	
13	Maturi	Dist-Unattended	115.00	34.00	
14	McCarthy Lake-Nashwauk, MN	Trans-Unattended	230.00	14.00	
15	Minntac-Mt. Iron, MN	Trans-Unattended	230.00	115.00	
16	Mud Lake, Brainerd, MN	Trans-Unattended	230.00	115.00	
17	Nashwauk-Nashwauk, MN	Dist-Unattended	115.00	23.00	
18	Pequot Lakes-North Pequot Lakes, MN	Dist-Unattended	115.00	34.00	
19	Pepin Lake-Swanville, MN	Dist-Unattended	115.00	34.00	
20	Pine River-Pine River, MN	Dist-Unattended	115.00	34.00	
21	Platte River-Royalton, MN	Dist-Unattended	115.00	34.00	
22	Ridgeview-Duluth, MN	Dist-Unattended	115.00	14.00	
23	Riverton-Riverton, MN	Trans-Unattended	230.00	115.00	
24	Riverton-Riverton, MN	Dist-Unattended	115.00	34.00	
25	Sandstone-Sandstone, MN	Dist-Unattended	69.00	46.00	
26	Sandstone-Sandstone, MN	Dist-Unattended	46.00	12.00	
27	Scanlon HE - Scanlon, MN	Dist-Unattended	23.00	14.00	
28	Scearcyville-Brainerd, MN	Trans-Unattended	115.00		
29	Shannon-Hibbing, MN	Trans-Unattended	230.00	115.00	
30	Silver Bay, Hill Side, MN	Dist-Unattended	115.00	14.00	
31	S-Laskin-Aurora, MN	Trans-Unattended	138.00	115.00	
32	S-Laskin-Aurora, MN	Trans-Unattended	115.00	46.00	
33	S-Laskin-Aurora, MN	Trans-Unattended	115.00	23.00	
34	Swan Lake	Dist-Unattended	115.00	34.00	
35	Swan Lake	Dist-Unattended	115.00	14.00	
36	Taconite Harbor-Taconite Harbor, MN	Trans-Unattended	138.00	115.00	
37	Taft-Grand Lake Township	Dist-Unattended	115.00	34.00	
38	Thomson HE-Thomson, MN	Trans - Attended	115.00	46.00	
39	Thomson HE-Thomson, MN	Trans - Attended	115.00	14.00	
40	Tower, MN	Dist-Unattended	115.00	46.00	

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Tri-County	Trans-Unattended	230.00		
2	Two Harbors, Two Harbors, MN	Dist-Unattended	115.00	14.00	
3	Two Harbors Switching Station	Trans-Unattended	115.00	14.00	
4	Verndale-Verndale, MN	Dist-Unattended	115.00	34.00	
5	Virginia-Virginia, MN	Dist-Unattended	115.00	46.00	
6	Virginia-Virginia, MN	Dist-Unattended	115.00	23.00	
7	Wing River-Verndale, MN	Trans - Unattended	230.00	115.00	
8	Zemple	Trans - Unattended	230.00	115.00	
9	Zemple	Dist - Unattended	115.00	23.00	
10					
11					
12					
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Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
13	5		Cap Banks	2	1,810	2
24	20	4	Regulators	9	1,015	3
140	73					4
40	13		Regulators/Capacitor	13	4	5
35	6					6
107	3		14 KV Capacitors	2	12	7
746	2	1	230 KV Capacitor	5	196	8
34	1					9
39	1					10
167	1					11
34	1		115kV Cap/34KV Cap	2	33	12
35	1		115 KV Capacitor	1	30	13
			230kV Capacitor	1	40	14
746	2		230 KV Capacitor	1	50	15
65	2					16
			115 KV Capacitor	1	20	17
						18
39	1					19
						20
8	1					21
65	3		Ground Transformer	1	8	22
62	2		115 KV Capacitor	1	27	23
20	1					24
39	1					25
						26
10	1					27
672	1					28
746	2		230 KV Capacitor	1	68	29
34	1					30
19	1					31
73	2	1				32
			115kV Capacitor	1	30	33
67	2					34
39	1					35
						36
78	2		7.5MVA GRD/7MVAR Cap	2	16	37
187	1					38
6	1					39
11	1		46 KV Capacitor	2	7	40

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
67	2		115kV Capacitor	2	31	1
180	2		115kV Phase Shifter		180	2
142	3					3
30	1					4
10	1					5
67	2		5 MVA/20 MVAR	2		6
187	1		20 MVA Reac/265Cap	8	335	7
47	3		115KV Cap./34KV Capa	2	35	8
34	1					9
8	1					10
15	1					11
10	1					12
10	1					13
						14
746	2		115 KV Capacitor	1	45	15
187	1					16
43	2		115 KV Capacitor	1	27	17
34	1					18
39	1					19
39	1					20
39	1					21
73	2					22
187	1		230 KV Capacitor	1	50	23
57	2		5 MVA GRD/22KV Cap	2	12	24
11	1					25
5	2					26
8	1					27
						28
374	2		45 MVAR 115KV Cap	3	113	29
10	1					30
187	1	1				31
23	2					32
15	1					33
30	1					34
39	1					35
187	1					36
13	1					37
13	1					38
10	1					39
39	1					40

Name of Respondent ALLETE, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
20	3					2
19	1		115 kV Capacitor	1	27	3
45	2		34 KV Capacitor	1	5	4
39	1		115 kV Capacitor	1	27	5
45	3		23 KV Capacitor	1	6	6
						7
374	2		115 kV Capacitor	1	30	8
10	1					9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
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						39
						40

Schedule Page: 426 Line No.: 1 Column: c

Voltages are nominal kV.
Taken as high voltage side.
Taken as the low voltage side.

30 Transmission Substations 6,000 MVA

124 Distribution Substations 2,167 MVA

Total Substations = 154 8,167 MVA

Schedule Page: 426 Line No.: 8 Column: i

Four 230kV 39 MVAR, One 230kV Capacitor Banks. Columns: I, J, K

Schedule Page: 426 Line No.: 17 Column: f

City of Brainerd owns #1-50 MVA and #2-50 MVA and #3-50 MVA Transformers Columns: F,G,I,J,K
115kV Capacitor has 1 Bank at 20 MVAR capacity

Schedule Page: 426 Line No.: 28 Column: g

Great River Energy owns three 500/230 kV Transformers Columns: F,G,I,J,K
Xcel Eergy owns all 500kV Reactors and 168 MVA-R SVC

Schedule Page: 426 Line No.: 33 Column: i

115kV Capacitor has 1 Bank at 29.7 MVAR capacity and City of Grand Rapids owns one 23kV Capacitor Bank at 8.6 MVAR capacity and two 115/23kv Transformers 50 MVA Columns: F,G,I,J,K

Schedule Page: 426.1 Line No.: 6 Column: f

Great River Energy owns one 115/34kV-30 MVA Transformer Columns: F,G

Schedule Page: 426.1 Line No.: 7 Column: f

Xcel Energy Owns six 230kV 44 MVAR Capacitor Banks Columns: F,G
Minnkota Power Cooperative owns one 20 MVA Reactor

Schedule Page: 426.1 Line No.: 8 Column: f

Great River Energy owns one 115/34.5kV 20 MVA Transformer Columns: F,G

Schedule Page: 426.1 Line No.: 29 Column: f

Great River Energy owns 230/69kV 50 MVA Transformer Columns: F,G

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
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19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Strategic Planning - ALLOC 12, 24, 25	SWL&P	146	108,408
23		ALLETE Enterprises	146	2,240,127
24		ALLETE Properties	146	166,058
25				
26	Human Resources - HEADCT 2, 6, ALLOC 33	SWL&P	146	2,179,596
27		ALLETE Enterprises	146	1,812,891
28		ALLETE Properties	146	6,064
29				
30	Accounting/Finance - ALLOC 8, 25	SWL&P	146	242,595
31		ALLETE Enterprises	146	1,544,284
32		ALLETE Properties	146	136,716
33				
34	Corporate Relations/Communications - ALLOC 12, 25	SWL&P	146	60,815
35		ALLETE Enterprises	146	414,552
36		ALLETE Properties	146	38,142
37				
38	Legal and Regulatory Support - ALLOC 25	SWL&P	146	86,082
39		ALLETE Enterprises	146	327,583
40		ALLETE Properties	146	11,285
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
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19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Environmental Services	SWL&P	146	53,246
23		ALLETE Enterprises	146	106,421
24				
25	Facilities Management - ALLOC 24	SWL&P	146	56,907
26		ALLETE Enterprises	146	14,394
27				
28	Information Tech Services - ITS 2, 6, 7, 8, 10, 12	SWL&P	146	1,354,070
29		ALLETE Enterprises	146	1,500,067
30				
31	Purchasing	SWL&P	146	120,867
32		ALLETE Enterprises	146	162,094
33				
34	Engineering	SWL&P	146	119,816
35		ALLETE Enterprises	146	233,676
36				
37	Risk Management - ALLOC 15	SWL&P	146	453,320
38		ALLETE Enterprises	146	754,141
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALLETE, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
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14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 21 Column: a

ALLOC03	This allocation method is used solely for Special Segment 4075 – Purchasing. Percentages are calculated based on number of purchase requests for each business unit using ALLETE's payable system.
ALLOC04	This allocation method is used solely for Special Segment 4080 – Accounts Payable. Percentages are calculated based on number of invoices processed for each business unit using ALLETE's payable system.
ALLOC12	Allocation assigns Special Segment costs to Minnesota Power's non-regulated and ALLETE's subsidiaries. Assignment between Minnesota Power non-regulated and subsidiaries is based on corporate equity in those entities. This allocation method has limited use and is used primarily for the allocation of shareholder or investor relations-related costs, Board of Director's costs, and Audit Services.
ALLOC14	Allocation percentages are based on a combination of annual Minnesota Power construction budget dollars and fixed asset balances as of a given date. The intent of this method is to assign costs that are associated with Minnesota Power's fixed assets. Budget amounts are taken from the most recent annual budgeted construction plan. Fixed asset balances by Minnesota Power regulated and non-regulated are retrieved from the fixed asset system as of a given date. Fixed asset balances are for those entities that are processed by MP and contained in the MP fixed asset system.
ALLOC15	Allocation percentages are based on a combination of methods using fixed asset balances as of a given date and employee headcount (HEADCT10). Currently, this method is utilized solely for a single Special segment - 4090 – Insurance. The assumption is that increases or decreases in the amount of costs to this special relate to physical assets or increases/decreases in the number of employees. An adjustment was made to subsidiaries to reflect the fact that they pay for much of their own specific insurance.
ALLOC24	All allocation percentages are based on fixed asset balances in Minnesota Power's fixed asset system as of a given date. Fixed asset balances are for Minnesota Power regulated, non-regulated and SWL&P are included.
ALLOC25	Allocation percentages are based on a combination of fixed asset balances and corporate equity. Specials that utilize this method are those that relate to all operational entities of ALLETE.
ALLOC27	Allocation percentages are based on a combination of fixed asset balances and corporate equity.
ALLOC28	This allocation method is used for general Minnesota Power business costs. Allocation percentages are assigned between Minnesota Power regulated and non-regulated. Percentages were assigned based on geographic, regulatory and strategic factors, such as location in relation to Duluth headquarters, planned initiatives, regulatory proceeding, etc.
ALLOC33	Allocation percentages are based on the number of participants in specific executive plans. Percentages are calculated by using the number of participants in each company business unit (Minnesota Power and subsidiaries).
ALLOC36	Allocation percentages are based on fixed asset balances in MP's fixed asset system as of a given date, inclusive of non-regulated land and property assets. This method was established for specific land activities, including efforts related to Minnesota Power non-utility land. This allocation method ensures that an adequate amount of costs are assigned as Non-Regulated.
HEADCT2	Headcount allocation based on the number of employees processed through the Oracle payroll system, including ALLETE/Minnesota Power, SWL&P and ALLETE Clean Energy. Relates to those activities that benefit ALLETE/ Minnesota Power, SWL&P and ALLETE Clean Energy employees.
HEADCT5	Headcount allocation which is based on number of ALLETE/Minnesota Power employees processed through the Oracle/HR payroll system. SWL&P is excluded as this entity does not receive benefit from the assigned activities, but rather performs this function individually.
HEADCT6	Allocation is based on the number of union employees at Minnesota Power and SWL&P. Employee count is from the Oracle/HR Payroll system.
ITS01	Allocation is based on the number of employees at Minnesota Power and SWL&P. Employee count is from the Oracle/HR Payroll system.
ITS02	Allocation percentages are based on the estimated usage of the Energy Management System (EMS). Provided by ITS Department.
ITS08	Allocation percentages are based on the number of employees processed through the Oracle/HR payroll system. Percentages are adjusted for SWL&P due to its general self-sufficiency for the activities that utilize these methods.
ITS20	Allocation percentages are based on the number of employees across the ALLETE organization. Employee counts are from the Oracle/HR Payroll system.
ITS21	Allocation percentages are based on the number of employees across the ALLETE organization, excluding US Water employees. Employee counts are from the Oracle/HR Payroll system.
ITS22	Allocation percentages are based on the number of desktops/laptops/tablets supported by the ITS Department across the ALLETE organization. Device counts are provided by the ITS Department.

ITS23	Allocation percentages are based on the number of desktops/laptops/tablets supported by the ITS Department across the ALLETE organization, excluding U.S. Water devices. Device counts are provided by the ITS Department.
ITS24	Allocation percentages are based on the number of desktops/laptops/tablets supported by the ITS Department across the ALLETE organization, excluding U.S. Water and BNI Energy devices. Device counts are provided by the ITS Department.
ITS25	Allocation percentages are based on the number of premises within Minnesota Power's and SWL&P's service territories. Premise counts are provided by the ITS Department.
ITS26	Allocation percentages are based on the number of meters within Minnesota Power's and SWL&P's service territories. Meter counts are provided by the ITS Department.
ITS27	Allocation percentages are based on the average electric load within Minnesota Power's and SWL&P's service territories. Electric load averages are provided by the ITS Department.
ITS28	Allocation percentages are based on the number of users of the Geospatial Information System within Minnesota Power and SWL&P. Geospatial Information System user counts are provided by the ITS Department.
ITS29	Allocation percentages are based on the number of Continuous Emissions Monitoring System data analyzers within Minnesota Power's regulated and non-regulated operations. Data analyzer counts are provided by the Generation IT Department.
ITS30	Allocation percentages are based on the number of employees across the ALLETE organization, excluding US Water and BNI employees. Employee counts are from the Oracle/HR Payroll system.