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

FORM 8-K/A
(Amendment No. 1)

CURRENT REPORT
Pursuant to Section 13 or 15 (d) of the Securities Act of 1934

Date of Report (Date of earliest event reported) January 15, 2021 (October 30, 2020)

CHUGACH ELECTRIC ASSOCIATION, INC.
(Exact name of registrant as specified in its charter)

Alaska	33-42125	92-0014224
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

5601 Electron Drive, Anchorage, AK	99518
(Address of Principal's Executive Offices)	(Zip Code)

Registrant's telephone number, including area code: **(907) 563-7494**

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communication pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

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

Section 2 – Financial Information

Item 2.01 Completion of Acquisition or Disposition of Assets

On October 30, 2020, Chugach closed on the previously reported transaction contemplated by the Asset Purchase Agreement ("APA") and acquired substantially all of the assets of Municipal Light & Power ("ML&P") from the Municipality Of Anchorage, Alaska ("MOA").

The audited consolidated financial statements (and accompanying notes) of ML&P as of December 31, 2019, 2018 and 2017, are included in this Amendment No. 1 on Form 8-K/A ("Amendment") as Exhibits 99.1, 99.2, and 99.3, and incorporated herein by reference.

The unaudited consolidated financial statements (and accompanying notes) of ML&P as of September 30, 2020, are included in this Amendment as Exhibit 99.4 and incorporated herein by reference.

The unaudited pro forma condensed consolidated financial statements for the nine months ended September 30, 2020, giving pro forma effect to the Business Combination are included in this Amendment as Exhibit 99.5 and incorporated herein by reference.

Item 9.01 Financial Statements and Exhibits.

Exhibit No.	Description
99.1	Financial Statements, Required Supplementary Information and Other Information of Municipal Light & Power as of December 31, 2019 and 2018
99.2	Financial Statements, Required Supplementary Information and Other Information of Municipal Light & Power as of December 31, 2018 and 2017
99.3	Financial Statements, Required Supplementary Information and Other Information of Municipal Light & Power as of December 31, 2017 and 2016
99.4	Monthly Business Report of Municipal Light & Power as of September 30, 2020
99.5	Unaudited Condensed Consolidated Pro Forma Financial Statements of the Registrant as of September 30, 2020

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: January 15, 2021

CHUGACH ELECTRIC ASSOCIATION, INC.

By: for Sherri Highers

Lee D. Thibert
Chief Executive Officer

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

A Major Enterprise Fund of the Municipality of Anchorage

Financial Statements,
Required Supplementary Information
and
Other Information

December 31, 2019 and 2018

(With Independent Auditor's Report Thereon)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

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BDO

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3601 C Street, Suite 600
Anchorage, AK 99503

Independent Auditor's Report

Honorable Mayor and Members of the Assembly
Municipality of Anchorage, Alaska

Report on the Financial Statements

We have audited the accompanying financial statements of the Electric Utility Fund, an enterprise fund of the Municipality of Anchorage, Alaska, as of and for the years ended December 31, 2019 and 2018, and the related notes to the financial statements, which collectively comprise the Electric Utility Fund's Alaska's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards,* issued by the Comptroller General of the United States. 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 the auditor's 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, the auditor considers internal control relevant to the entity'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 entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of the 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 the Electric Utility Fund as of December 31, 2019 and 2018, and the changes in financial position and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matters

As discussed in Note 1, the financial statements present only the Electric Utility Fund, and do not purport to, and do not present fairly the financial position of the Municipality of Anchorage, Alaska as of December 31, 2019 and 2018, the changes in its financial position, or where applicable, its cash flows for the years ended in accordance with accounting principles generally accepted in the United States. Our opinion is not modified with respect to this matter.

As discussed in Note 13 to the financial statements, the Electric Utility Fund is currently in the process of being sold to a third party. Our opinion is not modified with respect to this matter.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that Management's Discussion and Analysis on pages 4 through 16 and the schedules of the Utility's proportionate share of the net pension and net other postemployment benefit liability and Utility contributions to the pension and other postemployment benefit plans on pages 100 through 106 be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements that collectively comprise the Electric Utility Fund's basic financial statements. The statistical section is presented for purposes of additional analysis and is not a required part of the basic financial statements. The statistical section has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated June 30, 2020 on our consideration of the Electric Utility Fund's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Electric Utility Fund's internal control over financial reporting and compliance.

BDO USA, LLP

Anchorage, Alaska
June 30, 2020

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Management's Discussion and Analysis

December 31, 2019 and 2018

The Electric Utility Fund (Utility) is a public utility of the Municipality of Anchorage (Municipality or Anchorage). The following is a discussion and analysis of the Utility's financial performance, providing an overview of the financial activities for the years ended December 31, 2019 and 2018. This discussion and analysis is designed to assist the reader in focusing on the significant financial issues, provide an overview of the Utility's financial activities and identify changes in the Utility's financial position. We encourage readers to consider the information presented here in conjunction with the Utility's financial statements and accompanying notes, taken as a whole.

Financial Highlights

- The Utility's total plant increased $0.2 million or 0.03% in 2019 while decreasing $12.7 million or 1.4% in 2018. The increase in 2019 was due to depreciation and retirements keeping pace with additions to plant. The decrease in 2018 was due to depreciation and plant retirement exceeding additions to plant.
- Total assets and deferred outflows of resources exceeded total liabilities and deferred inflows of resources by $299.3 million at December 31, 2019 and by $285.2 million at December 31, 2018. Of these amounts, $69.7 million in 2019 and $69.7 million in 2018 were unrestricted and available to meet the Utility's ongoing obligations to customers and creditors.
- The Utility's total net position increased $14.1 million or 4.9% in 2019, compared to an increase of $15.8 million or 5.86% in 2018. The increase in net position in 2019 was primarily due to lower production costs, primarily fuel, higher investment income, and lower administrative costs. The restriction on paying dividends to the MOA also has contributed to the increase in net position since 2016.The increase in net position in 2018 was primarily due to lower fuel costs and a lower gas transfer price for internally produced gas. Depreciation also decreased significantly in 2018. Beginning net position was reduced by $2.5 million due to adoption of a new accounting standard in 2018.

Overview of the Financial Statements

The Utility is a business type activity of the Municipality that provides electrical services to a specific area of the Municipality. The Utility's activities are recorded in an enterprise fund of the Municipality.

Required Financial Statements

The Utility's financial statements offer short and long-term information about the activities of the Utility and collectively provide an indication of the Utility's financial health. The basic financial statements are prepared using the economic resources measurement focus and accrual basis of accounting.

The basic financial statements, presented on a comparative basis for the years ended December 31, 2019 and 2018, include Statements of Net Position, Statements of Revenues, Expenses, and Changes in Net Position and Statements of Cash Flows.

The *Statements of Net Position* present information on all of the Utility's assets, liabilities, deferred outflows of resources and deferred inflows of resources, with the difference reported as net position, and provides information about the nature and amounts of investments in resources and obligations to creditors.

The *Statements of Revenues, Expenses, and Changes in Net Position* report operating and non-operating revenues and expenses, and the change in net position of the Utility for the years presented.

The *Statements of Cash Flows*, using the direct method of presentation, provide information about the Utility's cash receipts and cash payments during the years presented. These statements report cash and cash-equivalent activities for each fiscal year resulting from operating activities, noncapital financing activities, capital and related financing activities, and investing activities. These statements also provide answers to such questions as, where did cash come from, what was cash used for, and what was the change in cash balance during the reporting periods.

The *Notes to Financial Statements* provide the reader with additional information that is essential to a full understanding of the data provided in the basic financial statements.

The *Required Supplementary Information* presents certain information concerning the progress in funding the Utility's obligation to provide pension and other postemployment benefits.

Financial Analysis of the Utility

One of the most important questions asked about the Utility's finances is whether the Utility, as a whole, is better or worse off as a result of the year's activities. The Statements of Net Position and the Statements of Revenues, Expenses, and Changes in Net Position report information about the Utility's activities in ways that will help answer this question. These two statements report the net position of the Utility and changes in net position for each of the years presented. You can think of the Utility's net position, the difference between assets, deferred outflows of resources, liabilities, and deferred inflows of resources as one way to, over time, provide a measure of the Utility's financial health or financial position. Over time, increases or decreases in the Utility's net position can indicate whether its financial health is improving or deteriorating. However, you will need to also consider other non-financial factors such as changes in economic conditions and customer growth, as well as legislative and regulatory mandates.

The Utility's total net position increased $14.1 million from beginning net position, during 2019 compared to an increase in net position of $18.3 million from beginning net position, as restated, during 2018. The following analysis focuses on the Utility's net position and changes in net position during the year.

A portion of the Utility's net position (71.8% and 70.2% as of December 31, 2019 and 2018, respectively) reflects its net investment in capital assets, such as gas and electric production, transmission and distribution facilities, less any related outstanding debt used to acquire those assets. Those capital assets are used to provide services to customers; consequently those assets are not available for future spending or to be used to liquidate any outstanding debt. The changes in net investment in capital assets reflects changes in plant assets over the year as well as changes in the related debt. The slight increase in 2019 was due to depreciation and retirements keeping pace with additions to plant. The decrease in 2018 was due to depreciation and plant retirement exceeding additions to plant. For an electric utility with aging distribution assets, the construction of new assets is often done to replace older assets, so the increase in plant from new construction is offset by the retirement of older assets. The Utility did not issue any new debt during either 2019 or 2018 and the redemption of debt kept pace with the reduction in plant assets, resulting in little change in the percentage of net position invested in capital assets.

An additional portion of the Utility's net position (4.9% and 5.3% as of December 31, 2019 and 2018 respectively) represent resources that are subject to external restriction for debt repayment and future operations. The Utility has two categories of restricted net position, restricted for debt service and restricted for operations. These restrictions are imposed by the trust agreement as debt covenants for the Utility's revenue bonds.

Net position restricted for debt service includes the restricted debt service investment, accrued bond interest and the revenue bond reserve investment offset by the portion of debt used to fund the reserve. The primary difference between the net amounts for 2019 and 2018 is due to market value adjustments to the reserve investments. Those adjustments were negative in 2018 and positive in 2019. Net position restricted for operations is required by bond covenants to be equal to 1/8 of current cash operating expenses. Cash operating expenses were lower in 2019 than 2018.

The unrestricted portion of the Utility's net position (23.3% and 24.4% as of December 31, 2019 and 2018, respectively) are available to be used to meet the Utility's obligations to creditors and customers. The changes in unrestricted net position in both 2019 and 2018 are due to an overall positive change in net position, as well as the changes in net position invested in capital assets and restricted net position. The Utility has maintained over $60 million in unrestricted cash, which makes up a large portion of unrestricted net position in both years.

Net Position

	December 31,		
	2019	2018	2017
Plant	$ 877,333,410	$ 877,091,133	$ 889,806,691
Restricted assets	75,850,262	69,889,012	108,827,334
Current and other assets	123,451,047	118,134,761	90,519,572
Deferred outflows of resources	1,550,632	1,961,254	1,372,834
Total assets and deferred outflows of resources	$ 1,078,185,351	$ 1,067,076,160	$ 1,090,526,431
Current and other liabilities	20,764,776	19,297,209	32,495,462
Long-term liabilities	556,283,043	557,574,293	564,728,095
Deferred inflows of resources	201,815,619	204,964,937	223,845,628
Total liabilities and deferred inflows of resources	$ 778,863,438	$ 781,836,439	$ 821,069,185
Net investment in capital assets	214,935,301	200,317,529	201,055,297
Restricted for debt service	326,473	-	71,082
Restricted for operations	14,391,000	15,206,000	14,235,000
Unrestricted	69,669,139	69,716,192	54,095,867
Total net position	$ 299,321,913	$ 285,239,721	$ 269,457,246

Notable components of changes in assets, liabilities, and deferred inflows and outflows of resources are discussed below.

Plant increased $0.2 million during 2019 compared to a decrease of $12.7 million during 2018. The primary reasons for those changes are as follows.

During 2019, the Utility pursued a vigorous construction schedule, building two new substations and replacing old power poles and continuing to upgrade electric meters to "smart" meters. Additions to construction work in progress (CWIP) during the year were $30.1 million, while $15.1 million in CWIP projects were placed in service. This resulted in net additions to plant assets of $35.9 million, offset by $29.2 million in depreciation and $6.1 million in plant retirements.

During 2018, the construction program resulted in $23.2 million in additions to CWIP, while $31.2 million in CWIP was placed in service. Net additions to plant were $23.5 million, offset by plant retirements of $7.4 million, and depreciation of $28.9 million.

Restricted assets increased $6.0 million during 2019 compared to a decrease $38.9 million during 2018.

During 2019, the primary reasons for the increase was activity in the restricted funds for the gas field. Those funds earned $2.6 million in interest revenue, were increased by $0.7 million in ARO surcharge revenue deposits, $1.9 million in gas sales and $1.8 million in interfund loan principal and interest payments. They were decreased by $0.6 million in rate stabilization payments, and $0.3 million in royalty and tax payments.

During 2018, the Regulatory Commission of Alaska (RCA) allowed the Utility to remove the restriction on $40.6 million in cash collected due to the rate increase and the Utility repaid $9.1 million in tax credits received in prior years from the State of Alaska. These reductions were offset by interest earnings, loan repayments, gas sales and surcharge revenue collections.

Current and other assets increased $5.3 million during 2019 compared to an increase of $27.6 million during 2018.

During 2019, the primary reason for the increase is the increase in the Utility's equity in general cash pool, or unrestricted cash. This increase continues an upward trend from 2016, due to rate increases; reduction in operating expenses, primarily the cost of fuel for the generators; and the restriction by the RCA on the Utility paying a dividend to the Municipality.

During 2018, the Utility's equity in general cash pool increased by $29.3 million primarily due to lifting of the restriction of funds collected from customers pursuant to the refundable rate increase granted by the RCA. Other receivables decreased by $1.7 million due to timing of payment of receivables. Prepaid items decreased $2.2 million due to accelerated payments in 2017 for purchased power.

Deferred outflows of resources decreased $0.4 million during 2019 and increased $0.6 million during 2018 as a result of changes in pension related items and accounting for other postemployment benefits.

During 2019, deferred outflows of resources related the pensions decreased significantly and deferred outflows of resources related to other post-retirement benefits decreased slightly due to changes in expectations and assumptions from the prior year.

During 2018, deferred outflows related to other post-retirement benefits were recorded for the first time due to implementation of GASB Statement No. 75.

Current and other liabilities increased $1.5 million during 2019 compared to a decrease of $13.2 million during 2018.

During 2019, accounts payable from current assets increased $1.3 million primarily due to increase in over-recovery of cost of power expenses from customers.

During 2018, accounts payable from current assets decreased $12.5 million primarily due to repaying prior year over-recovery of cost of power expenses from customers, and $0.5 million in pollution remediation liabilities were written off.

Long-term liabilities decreased $1.3 million during 2019 compared to a decrease of $7.2 million in 2018.

During 2019, the ARO was increased by $7.8 million, as a result of a cost of remediation assessment and a reserve study for the gas field. This is offset by a $1.3 million reduction in the pension liability, a reduction of $2.0 million in other postemployment benefits (OPEB) liability, and $7.7 million redemption of bonds.

During 2018, the primary driver of the change was a $0.9 million reduction in the pension liability, the addition of $2.3 million in OPEB liability due to adoption of new accounting standards, and $7.9 million redemption of bonds.

Deferred inflows of resources decreased $3.1 million in 2019 compared to a decrease of $18.9 million in 2018.

During 2019, contributions in aid of construction decreased by $5.3 million due to amortization in 2019 exceeding additions. Future BRU construction or natural gas purchases account increased by $2.0 million primarily $1.8 million in gas sales and $0.5 million in investment earnings.

During 2018, contributions in aid of construction decreased by $2.8 million due to amortization in 2018 exceeding additions. Deferred inflows of resources related to pensions decreased $0.7 million while deferred inflows of resources related to other postemployment benefits of $0.8 million were recorded due to the adoption of a new accounting standard. The future natural gas purchases account increased by $0.7 million in investment earnings and redemption of intercompany debt. Future BRU construction or natural gas purchases account decreased by $16.9 million primarily due to refunding tax credits offset by $2.2 million in gas sales and $0.1 million in investment earnings (see Note 9 (c)).

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Management's Discussion and Analysis

December 31, 2019 and 2018

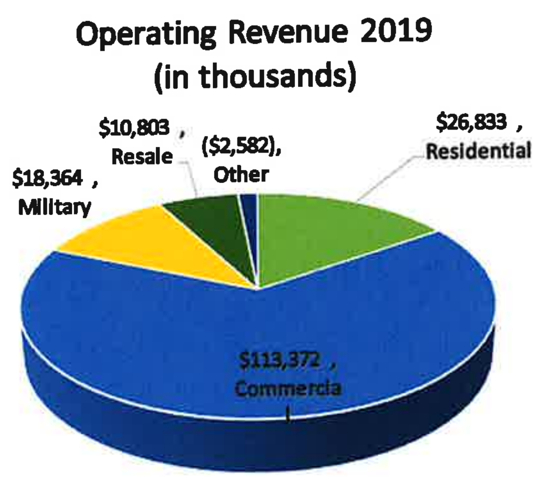
Revenues, Expenses, and Changes in Net Position

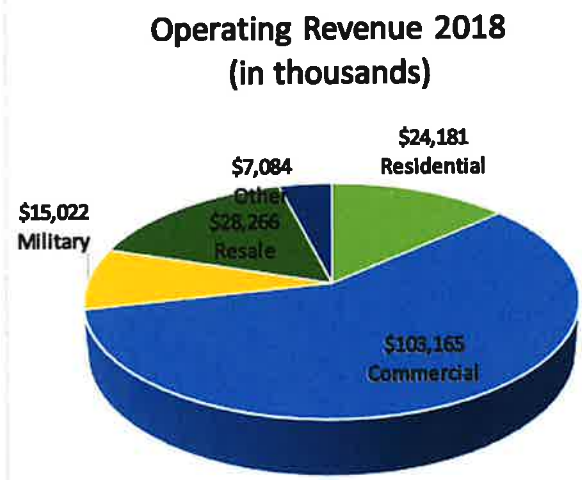
Changes in the Utility's net position can be determined by reviewing the following condensed schedule of revenues, expenses, and changes in net position for the years ended December 2019, 2018, and 2017:

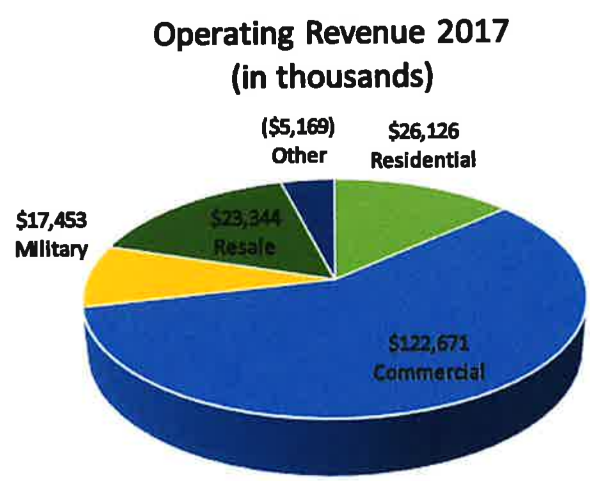
	Years ended December 31,		
	2019	2018	2017
Operating revenues:			
Residential sales	$ 26,832,744	$ 24,180,864	$ 26,125,850
Commercial and industrial sales	113,371,659	103,164,976	122,670,602
Military sales	18,364,179	15,021,531	17,452,871
Sales for resale	10,803,496	28,266,428	23,344,433
Other operating revenues	(2,581,581)	7,084,219	(5,169,343)
Operating revenues	166,790,497	177,718,018	184,424,413
Nonoperating revenues	9,521,971	3,878,498	4,868,051
Total revenues	176,312,468	181,596,516	189,292,464
Expenses:			
Production	76,650,484	80,038,875	84,409,875
Transmission	1,306,068	1,206,720	1,160,932
Distribution	14,596,098	13,508,019	11,609,032
Customer service and sales	4,260,728	4,139,729	4,285,142
Administrative and general	6,510,003	9,934,148	11,044,068
Regulatory debits (credits)	(1,642,549)	(8,026,635)	(4,028,641)
Taxes other than income	773,358	894,382	1,367,440
Depreciation, net of amortization	29,176,277	28,862,200	32,453,517
Operating expenses	131,630,467	130,557,438	142,301,365
Nonoperating expenses	20,953,871	23,136,095	22,768,624
Total expenses	152,584,338	153,693,533	165,069,989
Income before transfers	23,728,130	27,902,983	24,222,475
Transfers:			
Municipal Utility Service Assessment (MUSA)	(9,645,938)	(9,565,771)	(9,331,662)
Transfer to other funds	-	(29,418)	-
Change in net position	14,082,192	18,307,794	14,890,813
Beginning net position (restated in 2018)	285,239,721	266,931,927	254,566,433
Ending net position	$ 299,321,913	$ 285,239,721	$ 269,457,246

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Management's Discussion and Analysis
December 31, 2019 and 2018

Revenues by Source:







During 2019 total operating revenues were $166.8 million, a decrease of $10.9 million from 2018, compared to $177.7 million and a decrease of $7.7 million during 2018. Total kilowatt hours (kWh) sold decreased by 253.7 million in 2019 compared to an increase of 54.8 million in 2018. Components of the changes in revenues were:

Residential sales increased by $2.7 million and commercial and industrial sales increased by $10.2 million. and military sales revenue increased by $3.3 million. Sales for resale decreased by $17.5 million during the year. Warmer weather during the year contributed to lower kWh sold to retail customers. Overall, 8.9 million less kWh were sold to retail customers in 2019 than in 2018. Increases in dollar revenues were primarily due to higher Cost of Power Adjustment (COPA) revenues as a result of slightly increased fuel costs for the year. Military sales revenue increased by $3.3 million and kWh sales increased by 871,000. Sales for resale decreased by $17.5 million during the year. Sales for resale is wholesale power sold to other utilities and is dependent on a number of factors such as the cost of buying versus the cost to produce, the availability of power from other sources and price competition among sellers. In 2019, our primary customers purchased from other sources.

Other operating revenues decreased by $9.7 million due to over-recovery of COPA. Non-operating revenues increased by $5.6 million due to an increase in market conditions resulting in higher investment income for the year.

During 2018 total operating revenues were $177.7 million, a decrease of $6.7 million from 2017. Military sales revenue decreased by $2.4 million. Commercial and industrial sales decreased by $19.5 million while sales for resale increased by $4.9 million during the year. Retail sales decreases were primarily due to lower COPA. revenues as a result of lower fuel costs for the year and more efficient generation assets. Other operating revenues increased by $12.3 million due to under-recovery of COPA. Non-operating revenues decreased by just under $1 million due to lower investment income as a result of fewer assets invested.

Expenses by Category

Total expenses by category decreased $1.1 million during 2019 compared to a decrease of $11.4 million during 2018. Components of the changes were:

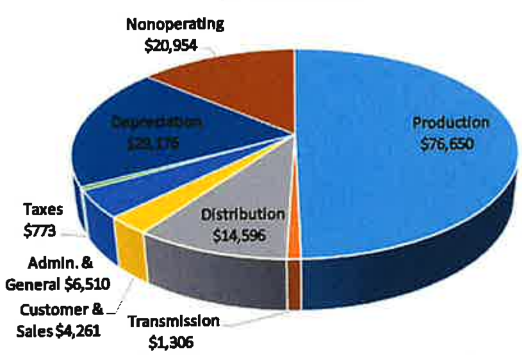
During 2019 operating expenses decreased $1.0 million from 2018 due to a $3.4 million decrease in production expenses (primarily fuel),and a $6.4 million increase in regulatory credits due to repayment of over-collection of COPA from customers. These two numbers are related to each other. Fuel costs are down primarily because of a decrease in fuel costs related to sales for resale. COPA is calculated based on projections of costs in providing that fuel for production. There will always be a variance between projected costs collected from customers and actual costs. Over and under recovery of actual costs are factored into future COPA calculations. Distribution expenses increased by $1 million. Administrative and general expenses decreased $3.4 million due to a loss of personnel, higher than expected recovery of administrative costs through overheads and the negative $2.4 million in OPEB expenses recorded as an adjustment of the OPEB liability in 2019. Non-operating expenses decreased $2.2 million because the Utility did not have a large loss on disposal of property as there was in 2018.

MUSA, which represents payments to the municipal government in lieu of property taxes, remained consistent with 2018, increasing just $80,000 due to an increase in mill rates.

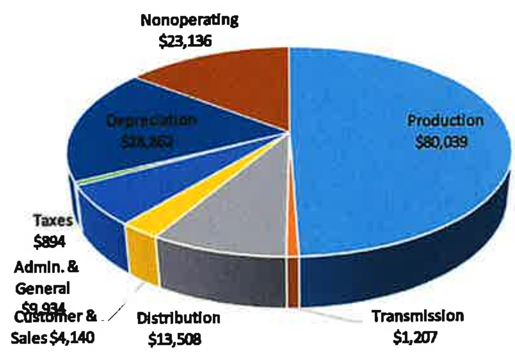
During 2018 operating expenses decreased $11.7 million from 2017 due to a $4.4 million decrease in production expenses (primarily fuel),and a $4 million increase in regulatory credits due to repayment of over-collection of COPA from customers. Distribution expenses increased by $1.9 million, administrative and general expenses decreased $1.1 million; depreciation expenses decreased $3.6 million primarily due to retirement of assets. Non-operating expenses increased just $0.4 million primarily due to increased short-term borrowing costs offset by decreases in other miscellaneous and interest expense and loss on disposal of property.

MUSA remained consistent with 2017, increasing just $0.2 million due to a decrease in plant assets and an increase in mill rates.

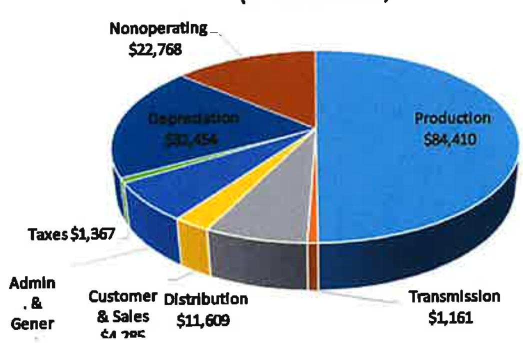
Expenses By Category 2019*
(in thousands)



Expenses By Category 2018*
(in thousands)



Expenses By Category 2017*
(in thousands)



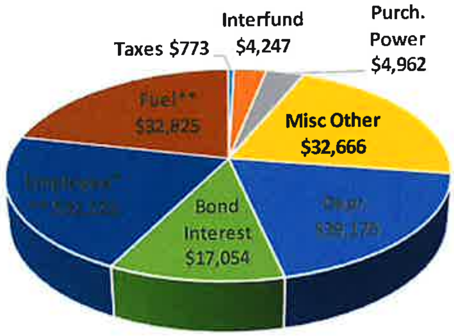
* Expenses by category excluding regulatory debits (credits)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

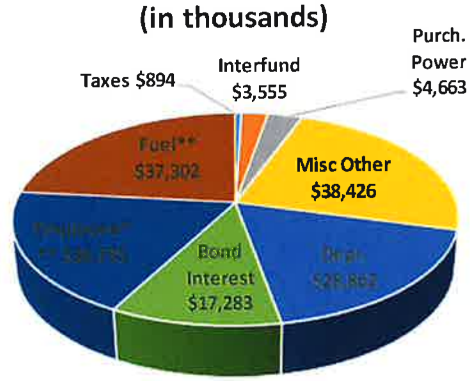
Management's Discussion and Analysis

December 31, 2019 and 2018

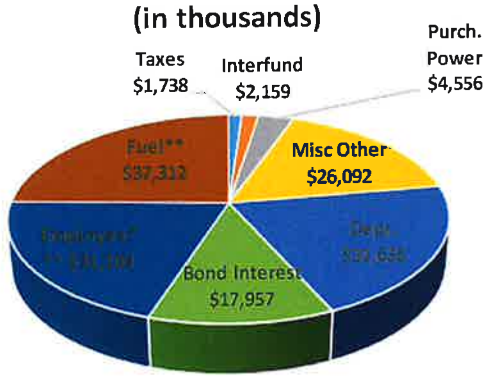
Expenses By Type 2019*
(in thousands)



Expenses By Type 2018*
(in thousands)



Expenses By Type 2017*
(in thousands)



*Expenses by type excluding regulatory debits (credits)

**Fuel expense includes purchased natural gas, transportation costs, diesel fuel used, and CINGSA.

***Employee expense includes general liability and workers compensation insurance.

Capital Assets - Plant

The Utility's investment in capital assets as of December 31, 2019 and 2018 was $877.3 million and $877.1 million, respectively (net of accumulated depreciation and depletion.) This included investments in gas and electric production, transmission and distribution related facilities, as well as general items such as buildings and vehicles. Plant increased 0.03% in 2019 and decreased 1.4 % in 2018.

The Utility's capital assets as of December 31, 2019, 2018, and 2017 were as follows:

	2019	2018	2017
Capital assets:			
Steam production	$ 244,907,281	$ 242,833,584	$ 242,833,584
Hydraulic production	8,443,889	8,408,752	6,932,007
Other production	308,691,969	309,766,612	309,370,891
Transmission plant	82,696,983	82,141,081	76,759,366
Distribution plant	302,760,359	296,099,145	280,188,291
Regional transmission and market operation plant	53,744	-	-
General plant	42,627,110	43,929,026	43,877,572
Miscellaneous intangible plant	15,034,843	14,904,003	15,116,282
Intangible plant	15,272,228	15,272,228	15,272,228
Gas production	354,019,552	346,454,777	345,231,780
Total capital assets	1,374,507,958	1,359,809,208	1,335,582,001
Total accumulated depreciation	(527,142,333)	(497,620,360)	(468,732,750)
Total construction work in progress	29,967,785	14,902,285	22,957,440
Net capital assets	$ 877,333,410	$ 877,091,133	$ 889,806,691

During 2019, the Utility completed some upgrades to its older generating units and replaced overhead line systems and continued undergrounding projects. Construction projects still in progress at year end included the rebuild of substation 8, several large cable undergrounding projects, generating Unit 7 cooling water skid and the major overhaul of Eklutna hydroelectric generator Unit 2.

During 2018, the Utility performed a major overhaul of one of its two hydroelectric generators at Eklutna and continued to upgrade its distribution lines, both overhead and underground. Construction projects still in progress at year end included generating Unit 7 cooling water skid, SCADA system upgrade and undergrounding projects.

Long Term Debt - Revenue Bonds and Notes Payable

As of December 31, 2019 and 2018, the Utility had outstanding long-term debt of $515.5 million and $524.4 million, respectively.

The Utility's long-term debt as of December 31, 2019, 2018, and 2017, were as follows:

	2019	2018	2017
Revenue bonds:			
Series 2005A	$ 10,870,000	$ 12,150,000	$ 17,565,000
Series 2009A	12,680,000	15,240,000	15,240,000
Series 2009B	114,760,000	114,760,000	114,760,000
Series 2014A	169,465,000	173,355,000	175,805,000
Unamortized discount	(415,811)	(446,018)	(476,692)
Unamortized premium	16,247,046	17,436,399	18,721,619
Total revenue bonds	323,606,235	332,495,381	341,614,927
Notes payable	191,900,000	191,900,000	191,900,000
Total long-term debt	$ 515,506,235	$ 524,395,381	$ 533,514,927

The Utility has not issued new revenue bonds since 2014. It is the intention of the Municipality to redeem or defease all long term debt pursuant to the sale of the Utility in 2020.

Bond Rating

At December 31, 2019, the Utility maintains the following underlying credit ratings:

Standard & Poor's	A+
Fitch	A+

In February 2020, Standard & Poor's reaffirmed the A+ rating of the Utility's Senior Debt. In January 2020, Fitch opted to do an internal review in light of the pending sale of the Utility and did not change its rating at that time.

Currently Known Facts, Decisions and Conditions

Sale of the Utility

On April 3, 2018, Anchorage voters approved an amendment to the Anchorage Municipal Charter authorizing the Municipality to sell the Utility to Chugach Electric Association (CEA) by Municipal ordinance. An asset purchase and sale agreement has been approved by the Anchorage Municipal Assembly and CEA's board of directors.

On May 28, 2020, the RCA issued an order addressing the acquisition dockets and approving the sale if the parties agree to modify the proposed transaction as required in the final order. (See Note 9(i)). At this time, CEA, the Municipality, and all the other parties in the docket have yet to decide whether they accept the conditions as ordered by the RCA. If they do accept the conditions and the acquisition goes forward, the expected closing date will be in the fall of 2020.

A successful acquisition of most of the assets of the Utility by CEA would have a significant effect on the financial position and results of operations of the Utility. The agreement, as approved with conditions by the RCA, requires that the Utility retain only the generation assets of Eklutna Hydroelectric Project and sell power to Chugach Electric Association (CEA) and Matanuska Electric Association (MEA) from those assets. (See Note 13).

Global Pandemic

In late January 2020 the World Health Organization ("WHO") announced a global health emergency regarding a new strain of virus called coronavirus (COVID-19). This virus originated from within China, and spread globally, including Alaska. Further, in March 2020, the WHO classified the coronavirus as a pandemic. On March 12, 2020, the mayor of Anchorage declared a state of emergency to protect and preserve public health and safety, and subsequently closed all civic, cultural and recreational facilities in the Municipality. The governor of Alaska declared a public health disaster as did the President of the United States. The governor instituted a number of public health measures that affected intrastate and interstate travel and the movement of goods and services.

Management is actively monitoring the global situation and assessing its effect on the Utility's financial condition, liquidity, operations, supply chain, and workforce. Given the daily evolution of the COVID-19 outbreak and the global responses to curb its spread, the Utility is not able to estimate the effects of the COVID-19 outbreak on its results of operations, financial condition, or cash flows for fiscal year 2020, however, the Utility expects a longer receivables cycle and potential reduction in commercial sales during the economic slowdown that appears to be resulting from the health emergency.

The state legislature has passed legislation that could enable the Utility or its successor to recover in future rates some of the impact of unpaid utility bills and extraordinary expenses related to responding to the emergency. The legislation also provides for deferred payment agreements with customers affected by the pandemic and needing to defer payment of their electric bills to future periods. Management anticipates a negative impact on its short-term cash flows as a result of these arrangements.

Cares Act Funding

On March 27, 2020 the President signed into law the "Coronavirus Aid, Relief and Economic Security (CARES) Act." The CARES Act, among other things, appropriated funds for the Coronavirus Relief Fund to be used to make payments for specified uses to states and certain local governments. There is no assurance the Utility is eligible for these funds or will be able to obtain them. The Utility continues to examine the impact that the CARES Act may have. Currently, the Utility is unable to determine the impact that the CARES Act will have on the Utility's financial condition, results of operations or liquidity.

Contacting the Utility's Financial Management

This financial report is designed to provide our customers, citizens, and creditors with a general overview of the Utility's finances and to demonstrate the Utility's accountability for the money it receives. If you have any questions about this report or need additional financial information, contact the Utility's Acting Chief Financial Officer, Mollie C. Morrison, at (907) 263-5205.

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Net Position

December 31, 2019 and 2018

Assets and Deferred Outflows of Resources	2019	2018
Plant:		
Plant in service, at cost	$ 1,359,235,730	1,344,536,980
Less accumulated depreciation and depletion	514,270,008	484,853,307
Net plant in service	844,965,722	859,683,673
Intangible plant, net	2,399,903	2,505,175
Construction work in progress	29,967,785	14,902,285
Total plant	877,333,410	877,091,133
Restricted assets:		
Current:		
Restricted equity in general cash pool - customer deposits	1,260,642	1,225,452
Noncurrent:		
Debt service investment	2,056,512	2,058,443
Revenue bond reserve investment	24,387,434	23,718,574
Revenue bond operations and maintenance investment	14,391,000	15,206,000
Future natural gas purchases investment	7,305,431	5,732,181
Future BRU construction or natural gas purchases investment	10,106,437	8,032,509
Asset retirement obligation sinking fund investment	16,342,806	13,915,853
Total restricted assets	75,850,262	69,889,012
Current assets:		
Equity in general cash pool	67,475,637	61,906,365
Net accounts receivable:		
Utility customers, less estimated uncollectibles of $218,815 in 2019 and $214,282 in 2018	8,184,445	8,319,226
Other receivables, less estimated uncollectibles of $270,393 in 2019 and $77,082 in 2018	7,287,162	7,306,860
Accrued interest	667,202	736,000
Unbilled reimbursable projects	-	131,864
Inventory of materials and supplies, at average cost	32,134,009	31,388,131
Prepaid Items	958,657	861,556
Total current assets	116,707,112	110,650,002
Other assets:		
Noncurrent:		
Unamortized regulatory assets	5,508,509	6,147,029
Unamortized debt expense	1,235,426	1,337,730
Total other assets	6,743,935	7,484,759
Total assets	1,076,634,719	1,065,114,906
Deferred outflows of resources:		
Deferred loss on refunding	24,588	61,057
Deferred outflows related to pensions	881,680	1,155,512
Deferred outflows related to other postemployment benefits	644,364	744,685
Total deferred outflows of resources	1,550,632	1,961,254
Total assets and deferred outflows of resources	$ 1,078,185,351	1,067,076,160

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Net Position, continued

December 31, 2019 and 2018

Liabilities, Deferred Inflows of Resources and Net Position	2019	2018
Current liabilities:		
Notes payable	$ 191,900,000	-
Accounts payable	13,316,710	12,035,116
Compensated absences payable	2,387,262	2,526,423
Accrued payroll liabilities	1,816,951	1,506,814
Accrued interest	1,722,475	1,813,590
Other liabilities	260,736	189,814
Long-term obligations maturing within one year	8,075,000	7,730,000
Total current liabilities (payable from current assets)	219,479,134	25,801,757
Current liabilities (payable from restricted assets):		
Customer deposits	1,260,642	1,225,452
Noncurrent liabilities:		
Notes payable	-	191,900,000
Asset retirement obligation	24,332,547	16,543,712
Unearned revenue	1,546,636	948,181
Net pension liability	10,094,592	11,361,736
Net other postemployment benefits liability	252,675	2,328,332
Obligation for undergrounding	4,550,358	1,996,951
Revenue bonds payable after one year, net of premium and discount	315,531,235	324,765,381
Total non-current liabilities	356,308,043	549,844,293
Total liabilities	577,047,819	576,871,502
Deferred inflows of resources:		
Contributions in aid of construction (net of amortization)	172,546,886	177,823,955
Future natural gas purchases	18,230,036	17,934,651
Future BRU construction or natural gas purchases	10,106,438	8,077,741
Deferred inflows related to pensions	517,705	285,157
Deferred inflows related to other postemployment benefits	414,554	843,433
Total deferred inflows of resources	201,815,619	204,964,937
Net position:		
Net investment in capital assets	214,935,301	200,317,529
Restricted for debt service	326,473	-
Restricted for operations	14,391,000	15,206,000
Unrestricted	69,669,139	69,716,192
Total net position	299,321,913	285,239,721
Total liabilities, deferred inflows of resources and net position	$ 1,078,185,351	1,067,076,160

See accompanying notes to basic financial statements.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Revenues, Expenses and Changes in Net Position
For the Years Ended
December 31, 2019 and 2018

	2019	2018
Operating revenues:		
Residential sales	$ 26,832,744	24,180,864
Commercial and industrial sales	113,371,659	103,164,976
Military sales	18,364,179	15,021,531
Sales for resale	10,803,496	28,266,428
Other operating revenues	(2,581,581)	7,084,219
Total operating revenues	166,790,497	177,718,018
Operating expenses:		
Production	76,650,484	80,038,875
Transmission	1,306,068	1,206,720
Distribution	14,596,098	13,508,019
Customer service and sales	4,260,728	4,139,729
Administrative and general	6,510,003	9,934,148
Regulatory credits	(1,642,549)	(8,026,635)
Taxes other than income	773,358	894,382
Depreciation, net of amortization	29,176,277	28,862,200
Total operating expenses	131,630,467	130,557,438
Total operating income	35,160,030	47,160,580
Nonoperating revenues:		
Investment income	7,237,517	1,197,610
Interest subsidy on Build America Bonds	2,443,046	2,437,406
PERS on behalf	544,512	154,073
OPEB on behalf	(703,104)	89,409
Total nonoperating revenues	9,521,971	3,878,498
Nonoperating expenses:		
Interest:		
Long-term obligations	16,467,228	16,794,977
Other interest	4,920,584	4,429,858
Total interest	21,387,812	21,224,835
Allowance for funds used during construction	(595,493)	(638,303)
Amortization of other assets	36,469	157,027
Loss on disposal of property	75,837	2,337,536
Other nonoperating expenses	49,246	55,000
Total nonoperating expenses	20,953,871	23,136,095
Net nonoperating revenues (expenses)	(11,431,900)	(19,257,597)
Income before transfers	23,728,130	27,902,983
Transfers:		
Municipal Utility Service Assessment	(9,645,938)	(9,565,771)
Transfers to other funds	-	(29,418)
Total transfers	(9,645,938)	(9,595,189)
Change in net position	14,082,192	18,307,794
Net position - beginning of year, as restated (for 2018)	285,239,721	266,931,927
Net position - end of year	$ 299,321,913	285,239,721

See accompanying notes to basic financial statements.

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Cash Flows
For the Years Ended
December 31, 2019 and 2018

	2019	2018
Cash flows from operating activities:		
Receipts from customers and users	$ 178,238,532	182,289,020
Other operating cash receipts	(1,851,857)	11,919,963
Payments to employees	(33,131,990)	(36,114,203)
Payments to vendors	(63,864,029)	(106,426,580)
Internal activity - payments made to other funds	(3,537,847)	(4,217,349)
Net cash provided by operating activities	75,852,809	47,450,851
Cash flows from noncapital financing activities:		
Transfer - Municipal Utility Service Assessment	(9,645,938)	(9,565,771)
Transfers to other funds	-	(29,418)
Net cash used by noncapital financing activities	(9,645,938)	(9,595,189)
Cash flows from capital and related financing activities:		
Interest payments on short-term debt	(4,920,584)	(4,429,858)
Principal payments on long-term debt	(7,730,000)	(7,865,000)
Interest payments on long-term debt	(17,615,185)	(17,781,999)
Interest subsidy on Build America Bonds	2,445,649	2,436,538
Acquisition and construction of capital assets	(33,137,236)	(20,599,776)
Contributed capital - customers	273,690	273,528
Contributed capital - intergovernmental agencies	135,912	521,344
Payments for interfund services used	(1,486,932)	(1,142,414)
Proceeds from sale of property	54,625	-
Net cash used by capital and related financing activities	(61,980,061)	(48,587,637)
Cash flows from investing activities:		
Net (deposits to) withdrawals from restricted funds	(5,926,060)	11,727,294
Investment income received	7,303,712	1,108,837
Net cash provided by investing activities	1,377,652	12,836,131
Net increase in cash	5,604,462	2,104,156
Cash, beginning of year	63,131,817	61,027,661
Cash, end of year	$ 68,736,279	63,131,817
Cash:		
Equity in general cash pool	$ 67,475,637	61,906,365
Interim rate escrow investment	-	-
Restricted equity in general cash pool	1,260,642	1,225,452
Cash, end of year	$ 68,736,279	63,131,817

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Cash Flows, continued
For the Years Ended
December 31, 2019 and 2018

	2019	2018
Reconciliation of operating income to net cash provided by operating activities:		
Operating income	$ 35,160,030	47,160,580
Adjustments to reconcile operating income to net cash provided (used) by operating activities:		
Depreciation, net of amortization	29,176,277	28,862,200
PERS on behalf	544,512	154,073
OPEB on behalf	(703,104)	89,409
Allowance for uncollectible accounts	197,844	41,125
Other nonoperating expenses	(49,246)	(55,000)
Changes in assets, deferred outflows of resources, liabilities, and deferred inflows of resources which increase (decrease) cash:		
Accounts receivable	(43,365)	1,966,709
Unbilled reimbursable projects	264,112	(21,239)
Inventories	(745,878)	689,064
Prepaid items	(97,101)	2,181,579
Unamortized regulatory assets	638,520	(3,179,841)
Deferred outflows of resources related to pensions	273,832	(31,378)
Deferred outflows of resources related to other postemployment benefits	100,321	(568,875)
Accounts payable	470,827	(13,876,244)
Compensated absences payable	(139,161)	(285,717)
Accrued payroll liabilities	310,137	(269,178)
Other liabilities	70,922	162,514
Customer deposits	35,190	39,226
Asset retirement obligation	7,788,835	719,980
Unearned revenue	466,207	83,650
Net pension liability	(1,267,144)	(909,157)
Net other postemployment benefits liability	(2,075,657)	489,294
Obligation for undergrounding	2,553,407	(257,061)
Other deferred inflows of resources	3,118,823	(14,997,948)
Deferred inflows of resources related to pensions	232,548	(718,256)
Deferred inflows of resources related to other postemployment benefits	(428,879)	(18,658)
Total cash provided by operating activities	$ 75,852,809	47,450,851
Non cash investing, capital and financing activities:		
Capital purchases on account	$ 810,767	906,478
Portion of plant from allowance for funds used during construction	595,493	638,303
Contributions in aid of construction funded from deferred inflows of resources	794,741	1,222,998
Total non cash investing, capital and financing activities	$ 2,201,001	2,767,779

See accompanying notes to basic financial statements.

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(1) Description of Business and Summary of Significant Accounting Policies

The first electric system serving Anchorage was installed in 1916 by the Alaska Engineering Commission, the agency of the United States Department of the Interior which constructed the Alaska Railroad. A small steam plant and several diesel power generators supplied Anchorage with electricity until 1929 when the private Anchorage Power and Light Company began supplying the community with electricity from a hydroelectric power plant on the Eklutna River located 15 miles northeast of downtown Anchorage. The Alaska Engineering Commission distribution system was purchased by Anchorage in 1932. Anchorage then acquired the Eklutna plant from the Anchorage Power and Light Company in 1943. This is what is now Anchorage Municipal Light and Power or the Electric Utility Fund, a public utility of the Municipality of Anchorage. The Utility now has six turbine generating units fired by natural gas and one heat recovery steam turbine generating unit. The Utility also has a thirty percent ownership in Southcentral Power Project and fifty-three and one-third percent ownership interest in the Eklutna Hydroelectric Project and is entitled to twenty-five and nine-tenths percent of the output of the Bradley Lake Hydroelectric Project. The Utility meets the majority of its natural gas requirements from its ownership interest in the Beluga River Gas Field (BRU), including the initial one-third interest acquired in December 1996. The Utility's goal in acquiring the working interest in the BRU was to lock in a critical resource for the long-term and provide a hedge against anticipated future increases in natural gas prices. During 2016 the Utility acquired 70% of a one-third working interest in the field from ConocoPhillips Alaska, Inc.(CPAI), increasing its working interest to 56.67%.

The accompanying financial statements include the activities of the Utility. The Utility is a major enterprise fund of the Municipality and not the Municipality as a whole. The Utility is subject to the regulatory authority of the RCA.

The Utility applies all applicable provisions of the Governmental Accounting Standards Board (GASB) which has authority for setting accounting standards for governmental entities. The accounting records of the Utility conform to the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Accounting and reporting treatment applied to the Utility is accounted for on a flow of economic resources measurement focus using the accrual basis of accounting. Revenues are recognized when they are earned and expenses are recognized at the time liabilities are incurred. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with the Utility's principal ongoing operations. All other revenues and expenses are reported as non-operating.

Description of Business and Summary of Significant Accounting Policies, continued

(a) Regulated Operations

The Utility meets the criteria, and accordingly follows the accounting and reporting requirements applicable to regulated operations. The Utility's rates are regulated by the RCA and as a result, revenues intended to recover certain costs are provided either before or after the costs are incurred, resulting in regulatory assets or liabilities. The following regulatory assets and liabilities are reflected in the accompanying financial statements:

- The Utility receives contributions in aid of construction, which it records as contributed plant in service and a deferred inflow of resources. The Utility amortizes contributed plant and the deferred inflow of resources over the useful life of the utility plant.
- The Utility accepted a monetary settlement in 2015 from its BRU partners for its 2014 underlift. The Utility used these funds to reduce its Gas Transfer Price (GTP) from July 1, 2016 through June 30, 2017. See Note 9(a).
- The Utility has a regulatory asset or liability account to capture the difference in the cost of power and revenue received through the Cost of Power Adjustment (COPA). See Note 9(b).
- The Utility has a regulatory asset or liability account to capture the difference in the amount of the Gas Fund revenue requirement and the actual amount of revenue collected from the Electric Fund. See Note 9(b).
- The Utility records proceeds from the sales of gas, net of royalties, taxes and an Asset Retirement Obligation (ARO) surcharge, as a regulatory liability, reported as deferred inflows of resources on the statements of net position. See Note 9(c).
- The Utility funds ARO expenses associated with future abandonment of the BRU through a surcharge to the Utility's GTP, which is deposited into a sinking fund. See Note 9(c) and (d).

Management believes that the recorded amounts of all regulatory assets are fully recoverable from ratepayers in the future.

(b) Management Estimates

In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and deferred outflows of resources, liabilities and deferred inflows of resources and the reporting of contingent assets and liabilities as of the date of the statement of net position and revenues and expenses for the period. Actual results could differ from those estimates. The more significant accounting and reporting policies and estimates applied in the preparation of the accompanying financial statements are discussed below.

Description of Business and Summary of Significant Accounting Policies, continued

(c) Cash Pools and Investments

The Municipality uses a central treasury to account for all cash and investments to maximize interest. Interest income on cash pool investments is distributed based on the average daily balance in the general cash pool. The Utility's investments are reported at fair value in the financial statements.

(d) Statements of Cash Flows

For purposes of the statements of cash flows, the Utility has defined cash as the demand deposits and all investments maintained in the general cash pool, regardless of maturity period, since the Utility uses the cash pools essentially as demand deposit accounts. Restricted assets in the general cash pool, except for customer deposits, have not been included in the definition of cash.

(e) ***Restricted Assets***

Certain proceeds of the Utility's revenue bonds, as well as resources set aside for their repayment, are classified as restricted assets on the statements of net position because their use is limited by applicable bond covenants. The revenue bond reserve investment account is used to report resources set aside to augment potential deficiencies from Utility operations that could adversely affect debt service payments. The debt service investment account is used to segregate resources accumulated for debt service payments over the next twelve months. The revenue bond operations and maintenance investment account represents funds set aside to comply with bond covenants requiring a reserve equal to one-eighth of the preceding year's operating expenses (as defined in the bond covenants).

The restricted equity in general cash pool-customer deposits account represents deposits provided by electric service customers as security for bill payment. Future natural gas purchases or BRU construction and ARO sinking fund investments are funds for which the RCA has specified the use.

(f) Inventories

Inventories are valued at weighted average cost. The cost of inventories are recorded as expenses when consumed rather than when purchased. Inventories consist of parts and materials used to maintain or build new transmission, distribution, and generation facilities. Scrap and nonusable materials in inventory are carried at net estimated realizable value until sold or otherwise disposed of.

The Utility also stores natural gas in a depleted field on the Kenai Peninsula. Cook Inlet Natural Gas Storage Alaska (CINGSA) started in 2012 and as of December 31, 2019 the Utility has stored 9.58 billion cubic feet of gas.

Description of Business and Summary of Significant Accounting Policies, continued

(g) *Property, Plant and Equipment*

Electric

Capital assets are stated at cost. Depreciation is computed by use of the straight-line method over the estimated economic life of the asset. Additions to electric plant in service are at original cost of items such as contracted services, direct labor and materials, indirect overhead charges and allowance for funds used during construction. The Utility capitalizes general plant assets valued at more than $25,000 that have an expected life in excess of one year. Contributed assets are recorded at the cost incurred by the Utility for the addition of such assets. Donated assets are recorded at acquisition value. Acquisition value is the price that would be paid to acquire an asset with equivalent service potential in an orderly market transaction at the acquisition date. For property replaced or retired, the cost of the property unit, plus removal costs less salvage, is charged to accumulated depreciation. Gain or loss is not recognized unless the Utility determines that such costs could not be recovered in rates. Costs for maintenance and repairs are expensed as incurred, except for major maintenance on generation assets, for which costs are collected into a regulatory asset and amortized over the period of utility, generally three to five years.

The Utility capitalizes Allowance for Funds Used During Construction (AFUDC) as a means to capture the cost of using both debt and equity funds to finance utility plant additions during the construction period in accordance with regulatory requirements. AFUDC of $595,493 and $638,303 were capitalized for the years ending December 31, 2019 and 2018, respectively.

Estimated lives of major plant and equipment categories follow:

Production plant	24 - 60 years
Hydraulic plant	40 - 45 years
Transmission plant	45 - 60 years
Distribution plant	17 - 55 years
General plant - buildings	40 - 60 years
Vehicles	16 - 20 years
Other general plant	5 - 20 years
Original gas field acquisition	23 years
Intangible plant	5 - 30 years

Gas

The acquisition of assets purchased with designated underlift settlement funds and Utility equity funds are being amortized using the units of production method, based upon proven reserves in accordance with the amortization method used for regulatory purposes. The acquisition of assets purchased with gas sale proceeds, and assets acquired from CPAI in the 2016 purchase, are being recorded as contributed plant and are being amortized using the units of production method, based on proven reserves in accordance with the amortization method used for regulatory purposes. No AFUDC is capitalized for gas field assets.

Description of Business and Summary of Significant Accounting Policies, continued

(h) Unbilled Revenues and Accounts Receivable

Electric revenues are based on cycle billings rendered to customers monthly. As a result of this cycle billing method, the Utility does not accrue revenue at the end of any fiscal period for services sold but not billed at such date. The unbilled revenues for the Utility are immaterial. An allowance for doubtful accounts is provided for receivables where there is a question of collectability. Utility receivables are presented in the statements of net position net of estimated uncollectible amounts.

Other receivables are primarily related to sales of electricity outside of the usual retail billing processes. The largest components of these receivables are related to sales of electricity to the military bases and wholesale sales for resale to other electric utilities.

Gas sales are calculated based upon volumes delivered and recorded as a regulatory liability, which is reported as deferred inflows of resources on the statements of net position (see Note 9(c)).

(i) Gas Balancing

The Utility has elected to account for underlifted gas from its ownership interest in the BRU according to the sales method. Therefore, the financial statements do not include a receivable or revenue for underlifted volumes for which the Utility did not elect to receive cash settlement. As of December 31, 2019 and 2018, the (overlift)/underlift balance was (521) and 23,106 Mcf, respectively. The Utility also has the option per the Gas Balancing Agreement to take cash settlements for any underlifted gas.

(j) Asset Retirement Obligation (ARO)

The Utility accounts for its ARO for its interest in the BRU in accordance with Accounting Standards Codification (ASC) Topic 980-410-20, formerly Statement of Financial Accounting Standards No 143, *"Accounting for Asset Retirement Obligations" (SFAS No 143)* and 18 CFR 101 General Instruction No 25, *Accounting for Asset Retirement Obligations (Regulations of the Federal Energy Regulatory Commission, Department of Energy, or FERC)*. ASC 980-410-20 and FERC General Instruction No 25 applies to the fair value of a liability for an ARO that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition of: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

In 2012 the Utility made its initial recording of the ARO asset and ARO liability with a beginning balance of $1,461,335 representing the fair value of the obligation at 1996 - the period when the obligation was incurred. The Utility recorded in 2012 $4,185,549 to the ARO liability representing total accretion expense that would have been incurred if the liability was accreted from the time the obligation was incurred through December 31, 2012. During 2013, the Utility commissioned a study of the costs associated with abandoning the BRU field and as a result of the findings of that study, adjusted the ARO liability and accretion as of December 2013.

Description of Business and Summary of Significant Accounting Policies, continued

Asset Retirement Obligation (ARO), continued

On April 22, 2016, the Utility purchased 70% of CPAI's one-third interest in the BRU. At that time a revised estimate was made of the life of the gas field. The Utility's obligation for an ARO was adjusted for the increased liability and changes in estimated life and discount rate.

During 2019, the Utility commissioned a study of the costs associated with abandoning the BRU field and also a study of remaining gas reserves, and, as a result of the findings of both studies, the Utility adjusted the ARO liability and accretion, for regulatory purposes as of January 1, 2019.

As of December 31, 2016, the Utility entered into an agreement with the State of Alaska Department of Natural Resources (DNR) to establish an ARO investment fund to meet its obligations for dismantling, removing and restoring the land and property to a condition acceptable to the commissioner of the DNR in accordance with the terms and conditions of assigned leases and applicable statutes and regulations. The balance of the ARO investment fund was $16,342,806 and $13,915,853 at December 31, 2019 and 2018, respectively.

A schedule of changes in the ARO balance for the years ending December 31, 2019 and 2018 is as follows:

	2019	2018
Asset to be retired:	Gas Field	
Beginning carrying value	$ 16,543,712	$ 15,823,732
Current year changes to the liability balance	-	-
Current year settled	-	-
Current year accretion	1,018,801	719,980
Change in assumption or cash flow revisions	6,770,034	-
Ending ARO	$ 24,332,547	$ 16,543,712

(k) Discount or Premium on Revenue Bonds Payable

The discount or premium on revenue bonds payable is amortized over the life of the related bond issues using the effective interest method.

(l) Compensated Absences

The Utility records employee leave, which includes sick leave, when earned.

Description of Business and Summary of Significant Accounting Policies, continued

(m) *Deferred Outflows and Inflows of Resources*

The Utility enters into transactions that result in the consumption or acquisition of resources in one period that are applicable to future periods. These consumptions and acquisitions of resources are reported in the statements of net position as deferred outflows and inflows of resources, respectively. The Utility records deferred outflows of resources related to pensions, other postemployment benefits and deferred loss on refunding of bonds, and deferred inflows of resources related to pensions and other postemployment benefits, contributions in aid of construction and certain items related to the operation of the BRU.

(n) Net Position

The Utility's net position is categorized as net investment in capital assets, restricted or unrestricted. The Utility's restricted net position represents assets restricted for payment of debt service, or restricted for operations, in accordance with covenants of the related revenue bond indentures. It is the Utility's policy to evaluate whether to use restricted or unrestricted resources to make certain payments, on a case by case basis, when both restricted and unrestricted assets are available for the same purposes.

(o) *Intragovernmental Charges*

Certain functions of the Municipality of a general and administrative nature are centralized and the related costs are allocated to the various funds of the Municipality, including the Utility. Such costs allocated to the Utility totaled $4,765,388 and $4,214,954 for the years ended December 31, 2019 and 2018, respectively, including general liability and workers compensation of $537,311 for 2019 and $660,414 for 2018.

(p) Utility Revenue Distribution/Municipal Service Assessment (MUSA)

Prior to 2006, the RCA restricted the Utility from making a revenue distribution or paying the gross receipts portion of the MUSA. That restriction was removed in December 2005. The Utility made an annual revenue distribution to the Municipality for the years 2006 - 2015, which by Ordinance, was up to a maximum of 5% of the Utility's gross revenues, excluding restricted revenues. During those years the Utility also included the gross receipts portion, considered supplemental MUSA, at 1.25% times the actual gross operating revenues in its payment of MUSA. During 2017, the Municipality eliminated the gross receipts portion of the MUSA and revised the methodology for calculating the Utility Revenue Distribution.

Beginning January 1, 2016, the Utility is restricted by the RCA from making revenue distributions to the Municipality, with the exception of MUSA. The Utility's distribution for MUSA in 2019 and 2018 was $9,645,938 and $9,565,771, respectively.

Description of Business and Summary of Significant Accounting Policies, continued

(q) Environmental

The Utility has adopted an aggressive policy designed to identify and mitigate the potential effects of past, present, and future operational activities that may result in environmental impact. It is the Utility's accounting policy to record a liability when the likelihood of responsibility for an environmental impact is probable and the cost of mitigating the impact is estimable within reasonable limits. Such costs are capitalized if they result in an extension of the assets' life, increase the capacity, or improve the safety or efficiency of property owned by the Utility; or mitigate or prevent environmental contamination that has yet to occur and that otherwise may result from future operations or activities. There were no environmental issues that met the Utility's accounting policy and accordingly, no provision has been made in the accompanying financial statements for any potential liability.

(r) Net Pension Liability

For purposes of measuring net pension liability, deferred outflows and inflows of resources related to pensions and pension expenses, information about the fiduciary net position of the Public Employees' Retirement System (PERS) and additions to/from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Details regarding the net pension liability are discussed in Note 7.

(s) Net Other Postemployment Benefits (OPEB) Liability

For purposes of measuring net OPEB liability, deferred outflows and inflows of resources related to OPEB and OPEB expenses, information about the fiduciary net position of PERS and additions to/from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Details regarding the net OPEB liability are discussed in Note 7.

(t) Reclassifications

Certain amounts previously reported may have been reclassified to conform to current presentations. The reclassifications had no effect on the previously reported change in net position.

(2) Change in Accounting Principle

As discussed in Note 7 to the financial statements, the Utility participates in the PERS plans. In 2018, the Utility adopted the provisions of GASB Statement No. 75 *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, which, among other accounting and reporting criteria, requires the Utility to recognize its proportional share of the net OPEB liability (and related deferred inflows and outflows of resources), as of the beginning of the Utility's fiscal year. As a result of the implementation of this statement, the Utility recorded an opening balance adjustment in 2018 to reflect opening balance OPEB liabilities and related accounts and to decrease opening net position as follows:

Opening net position as originally presented	Change in accounting principle adjustment	Opening net position, as restated after change in accounting principle
$ 269,457,246	$ (2,525,319)	$ 266,931,927

(3) Cash and Investments

At December 31, 2019 and 2018, the Utility had cash and investments in the Municipality's general cash pool (Central Treasury). The Utility also carries certain balances in a separate account for Asset Retirement Obligations. At December 31, 2019 and 2018, the Utility had the following cash and investments, with fixed income maturities as noted:

December 31, 2019:

	Fixed Income Investment Maturities (in years)				
Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
Utility Share of Petty Cash	$ 1,000				
Central Treasury - Unrestricted					
Money Market Funds	$ 14,721,342				
Repurchase Agreements	61,467,262	$ 61,467,262	$ –	$ –	$ –
Commercial Paper	2,824,608	2,824,608	–	–	–
U.S. Treasuries	90,725,434	5,367,758	68,506,311	16,690,855	160,510
U.S. TIPS	4,133,704	–	1,728,030	2,405,674	–
U.S. Agencies	54,795,702	29,450,138	5,532,580	6,180,849	13,632,135
Municipal Bonds	58,119	–	15,399	–	42,720
Asset-Backed Securities**	24,545,951	136,466	14,855,882	2,183,330	7,370,273
Corporate Fixed Income Securities	119,800,517	33,255,449	44,015,469	40,511,276	2,018,323
Domestic Equities***	38,448				
	$ 373,111,087	$ 132,501,681	$ 134,653,671	$ 67,971,984	$ 23,223,961

Cash and Investments, continued

December 31, 2019, continued

Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
	Fixed Income Investment Maturities (in years)				
Central Treasury - Restricted					
Money Market Funds	$ 22,921,889				
Repurchase Agreements	10,190,948	$ 10,190,948	$ –	$ –	$ –
Commercial Paper	468,305	468,305	–	–	–
U.S. Treasuries	34,608,937	889,946	30,925,123	2,767,256	26,612
U.S. TIPS	685,346	–	286,498	398,848	–
U.S. Agencies	25,072,613	4,882,677	16,905,048	1,024,752	2,260,136
Municipal Bonds	9,636	–	2,553	–	7,083
Asset-Backed Securities**	4,069,589	22,625	2,463,027	361,985	1,221,952
Corporate Fixed Income Securities	19,862,293	5,513,578	7,297,532	6,716,556	334,627
Domestic Equities***	6,375				
	$ 117,895,931	$ 21,968,079	$ 57,879,781	$ 11,269,397	$ 3,850,410
Utility share of Municipal Central Treasury	$ 126,983,093				
Asset Retirement Obligation Fund					
Money Market Funds	$ 86,590				
U.S. Treasuries	5,554,268	$ 131,577	$ 2,876,763	$ 875,241	$ 1,670,687
Asset-Backed Securities**	2,626,852	25,337	–	207,690	2,393,825
Corporate Fixed Income Securities	2,273,211	100,263	1,068,347	583,553	521,048
U.S. TIPS	1,608,253	1,608,253	–	–	–
Domestic Equity Funds	2,505,196				
International Equity Funds	863,848				
Real Estate Funds	824,588				
	$ 16,342,806	$ 1,865,430	$ 3,945,110	$ 1,666,484	$ 4,585,560
Total Utility cash and investments	$ 143,325,899				

* Includes accrued income.

** Includes asset-backed securities, residential and commercial mortgage-backed securities.

*** In 2019, the Central Treasury obtained an equity position when a corporate fixed income security was restructured via bankruptcy. The Municipality has chosen to hold this position until it is advantageous to sell it.

Cash and Investments, continued

December 31, 2018:

Investment Type		Fair Value*		Fixed Income Investment Maturities (in years) Less Than 1		1 - 5		6 - 10		More Than 10
Utility Share of Petty Cash	**$**	**1,000**								
Central Treasury - Unrestricted										
Money Market Funds	$	21,308,292								
Repurchase Agreements		22,398,105	$	22,398,105	$	–	$	–	$	–
U.S. Treasuries		148,917,831		80,567,294		55,484,846		12,414,634		451,057
U.S. Agencies		20,351,315		10,114		10,552,227		5,456,530		4,332,444
Asset-Backed Securities**		25,781,328		394,826		17,416,412		2,667,894		5,302,196
Corporate Fixed Income Securities		136,435,070		40,724,193		55,624,808		38,378,958		1,707,111
	$	375,191,941	$	144,094,532	$	139,078,293	$	58,918,016	$	11,792,808
Central Treasury - Restricted										
Money Market Funds	$	22,072,465								
Repurchase Agreements		3,164,717	$	3,164,717	$	–	$	–	$	–
U.S. Treasuries		34,914,468		11,383,671		21,712,952		1,754,113		63,732
U.S. Agencies		21,222,562		1,429		19,838,011		770,974		612,148
Asset-Backed Securities**		3,642,746		55,787		2,460,834		376,957		749,168
Corporate Fixed Income Securities		19,277,450		5,754,082		7,859,449		5,422,715		241,204
	$	104,294,408	$	20,359,686	$	51,871,246	$	8,324,759	$	1,666,252
Utility share of Municipal Central Treasury	**$**	**117,879,524**								
Asset Retirement Obligation Fund										
Money Market Funds	$	85,668								
U.S. Treasuries		4,096,389	$	506,386	$	1,250,725	$	1,420,655	$	918,623
U.S. TIPS		1,360,928		–		1,360,928		–		–
Asset-Backed Securities**		2,536,984		–		120,909		367,506		2,048,569
Corporate Fixed Income Securities		2,478,383		99,797		973,570		854,342		550,674
Domestic Equity Funds		2,061,138								
International Equity Funds		653,859								
Real Estate Funds		642,504								
	$	13,915,853	$	606,183	$	3,706,132	$	2,642,503	$	3,517,866
Total Utility cash and investments	**$**	**131,795,377**								

* Includes accrued income.

** I Includes asset-backed securities, residential and commercial mortgage-backed securities.

Cash and Investments, continued

Reported in the Statements of Net Position:

	2019	2018
Restricted assets:		
Customer deposits	$ 1,260,642	$ 1,225,452
Debt service investment	2,056,512	2,058,443
Revenue bond reserve investment	24,387,434	23,718,574
Revenue bond operations and maintenance investment	14,391,000	15,206,000
Future natural gas purchases investment	7,305,431	5,732,181
Future BRU construction or natural gas purchases investment	10,106,437	8,032,509
Asset retirement obligation sinking fund investment	16,342,806	13,915,853
Total restricted assets	$ 75,850,262	$ 69,889,012
Unrestricted equity in general cash pool, including petty cash	67,475,637	61,906,365
Total Utility cash and investments	$ 143,325,899	$ 131,795,377

(a) Municipal Central Treasury

The Municipality manages its Central Treasury in four portfolios; one internally managed portfolio and three externally managed duration portfolios based on liability duration and cash needs: working capital, contingency reserve and strategic reserve.

The Municipality maintains a comprehensive policy over cash and investments that is designed to mitigate risks while maximizing investment return and providing for operating liquidity. Pursuant to Anchorage Municipal Code (AMC) 6.50.030, the Municipality requires investments to meet specific rating and issuer requirements.

Both externally and internally managed investments are subject to the primary investment objectives outlined in AMC 6.50.030, in priority order as follows: safety of principal, liquidity, return on investment and duration matching. Consistent with these objectives, AMC 6.50.030 authorizes investments that meet the following rating and issuer requirements:

- Obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government sponsored corporations and agencies.
- Corporate debt securities that are guaranteed by the U.S. government or the Federal Deposit Insurance Corporation (FDIC) as to principal and interest.
- Taxable and tax-exempt municipal securities having a long-term rating of at least A- by a nationally recognized rating agency or taxable or tax-exempt municipal securities having a short-term rating of at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch.

Cash and Investments, continued

Municipal Central Treasury, continued

- Debt securities issued and guaranteed by the International Bank for Reconstruction and Development (IBRD) and rated AAA by a nationally recognized rating agency.

- Commercial paper, excluding asset-backed commercial paper, rated at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch.

- Bank debt obligations, including unsecured certificates of deposit, notes, time deposits, and bankers' acceptances (with maturities of not more than 365 days), and deposits with any bank, the short-term obligations of which are rated at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch and which is either:

    a) Incorporated under the laws of the United States of America, or any state thereof, and subject to supervision and examination by federal or state banking authorities; or
    b) Issued through a foreign bank with a branch or agency licensed under the laws of the United States of America, or any state thereof, or under the laws of a country with a Standard & Poor's sovereign rating of AAA, or a Moody's sovereign rating for bank deposits of Aaa, or a Fitch national rating of AAA, and subject to supervision and examination by federal or state banking authorities.

- Repurchase agreements secured by obligations of the U.S. government, U.S. agencies, or U.S. government-sponsored corporations and agencies.

- Dollar denominated corporate debt instruments rated BBB- or better (investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Dollar denominated corporate debt instruments rated lower than BBB- (non-investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency, including emerging markets.

- Dollar denominated debt instruments of foreign governments rated BBB- or better (investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Asset Backed Securities (ABS), excluding commercial paper, collateralized by: credit cards, automobile loans, leases and other receivables which must have a credit rating of AA- or above by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Mortgage Backed Securities, including generic mortgage-backed pass-through securities issued by Ginnie Mae, Freddie Mac, and Fannie Mae, as well as non-agency mortgage-backed securities, Collateralized Mortgage Obligations (CMOs), or Commercial Mortgage-Backed Securities (CMBS), which must have a credit rating of AA- or better by Standard & Poor's or the equivalent by another nationally recognized rating agency.

Cash and Investments, continued

Municipal Central Treasury, continued

- Debt issued by the Tennessee Valley Authority
- Money Market Mutual Funds rated Am or better by Standard & Poor's, or the equivalent by another nationally recognized rating agency, as long as they consist of allowable securities as outlined above.
- The Alaska Municipal League Investment Pool (AMLIP), except that the Working Capital portfolio may not be invested in AMLIP.
- Mutual Funds consisting of allowable securities as outlined above.
- Interfund Loans from a Municipal Cash Pool to a Municipal Fund.

In addition to providing a list of authorized investments, AMC 06.50.030 specifically prohibits investment in the following:

- Structured Investment Vehicles.
- Asset Backed Commercial Paper.
- Short Sales.
- Securities not denominated in U.S. Dollars.
- Commodities.
- Real Estate Investments.
- Derivatives, except "to be announced" forward mortgage-backed securities (TBAs) and derivatives for which payment is guaranteed by the U.S. government or an agency thereof.

The Investment Management Agreement (IMA) for each external manager and the policy and procedures (P&P) applicable to the internally managed investments provide additional guidelines for each portfolio's investment mandate. The IMA limits the concentration of investments for the Working Capital portfolio at the time new investments are purchased as follows, with year-end concentrations listed for 2019 and 2018:

Working Capital Portfolio

Investment Type	Concentration Limit	Holding % at December 31	
		2019	2018
U.S. Government Securities*	50% to 100% of investment portfolio	27%	53%
Repurchase Agreements	0% to 50% of investment portfolio	42%	13%
Commercial Paper	0% to 25% of investment portfolio Maximum 5% per issuer	1%	0%
Corporate Fixed Income**	0% to 25% of investment portfolio Maximum 5% per issuer	17%	18%
Money Market Mutual Funds	0% to 25% of investment portfolio	13%	16%
		100%	100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.

**The maximum exposure to Corporate floating and variable rate debt securities in the Working Capital Portfolio is 10 percent. Corporate Fixed Income Debt Securities must have a final maturity within one (1) year of purchase, and Corporate Floating Rate or Variable Rate Debt Securitites must have a final maturity within two (2) years of purchase

The P&P limits the concentration of investments for the internally managed portfolio at the time new investments are purchased as follows, with year-end concentrations listed for 2019 and 2018:

Internally Managed Portfolio

Investment Type	Concentration Limit	Holding % at December 31	
		2019	2018
U.S. Government Securities*	50% to 100% of investment portfolio	10%	71%
Money Market Mutual Funds**	0% to 25% of investment portfolio	90%	29%
		100%	100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.

**The Internally Managed Portfolio contained an excess of cash equivalents at December 31, 2019 in anticipation of planned spending within a week. The portfolio was back in compliance the first week of 2020.

Cash and Investments, continued

(b) Beluga River Asset Retirement Obligation Fund

Funds set aside to pay for dismantling, removing, and restoring assets of the Beluga River Unit gas field were transferred from the MOA Central Treasury to a separate investment portfolio in 2017, per assembly ordinance.

The Beluga River Asset Retirement Obligation Fund is managed to maximize capital appreciation with a long-term rate of return. The Fund is authorized to invest in the following assets:

- Domestic equities and International equities, including real estate investment trusts.
- Investment grade dollar-denominated fixed income securities.
- Cash and money market instruments.

The Beluga River Asset Retirement Obligation Fund limits the concentration of its investments as follows:

Investment Type	Lower Limit	Upper Limit	Target	Investment Holding % at December 31, 2019 and 2018
Domestic Equities:				
Large Cap	5%	20%	13%	13%
Mid Cap	0%	5%	1%	1%
Small Cap	0%	5%	1%	1%
International Equities:				
Developed	0%	10%	4%	4%
Emerging Markets	0%	5%	1%	1%
Real Estate:				
Real Estate Funds	0%	10%	5%	5%
Fixed Income:				
Domestic Fixed Income	55%	75%	65%	64%
TIPS	5%	15%	10%	10%
Cash & Cash Equivalents:				
Cash Equivalents	0%	15%	0%	1%
				100%

(c) Interest Rate Risk

Interest rate risk is the risk that changes in interest rates will adversely affect the fair value of an investment. The externally managed portfolios of the Municipal Central Treasury utilize the duration method to measure exposure to interest rate risk.

Duration is a measure of an investment's sensitivity to interest rate changes, and represents the sensitivity of an investment's market price to a one percent change in interest rates. The effective duration of an investment is determined by its expected future cash flows, factoring in uncertainties introduced through options, prepayments, and variable rates. The effective duration of a pool is the average fair value weighted effective duration of each security in the pool.

Cash and Investments, continued
Interest Rate Risk, continued

AMC 6.50.030 requires the Working Capital Portfolio have a duration of zero to 270 days. At December 31, 2019, the Working Capital Portfolio had a duration of 0.09 years, or approximately 33 days, and was within the targeted duration. At December 31, 2018, the Working Capital Portfolio had a duration of 1.37 years, or approximately 500 days, and was not within the targeted duration. AMC 6.50.030 also requires that the Contingency Reserve Portfolio have an average duration within half a year of its benchmark. At December 31, 2019, the Contingency Reserve Portfolio had a duration of 1.83 years as compared to its benchmark, Barclays 1-3 Year Government Index, which had a duration of 1.87 years. At December 31, 2018, the Contingency Reserve Portfolio had a duration of 1.83 years as compared to its benchmark, Barclays 1-3 Year Government Index, which had a duration of 1.90 years. AMC 6.50.030 requires the Strategic Reserve Portfolio have a maximum duration no greater than one year in excess of its benchmark.

At December 31, 2019, the Strategic Reserve Portfolio had a duration of 3.21 years as compared to its benchmark, Barclays Intermediate Government/Corporate Index, which had a duration of 3.62 years. At December 31, 2018, the Strategic Reserve Portfolio had a duration of 3.12 years as compared to its benchmark, Barclays Intermediate Government/Corporate Index, which had a duration of 2.91 years.

The effective duration of the externally managed portfolio of the Municipal Central Treasury working capital portfolio at December 31, 2019, was 0.09 years, which is within the targeted duration of +/-.25 years of the Merrill Lynch 90-day Treasury Bill Index, as required per Alaska Permanent Capital Management Investment Manager Agreement. The effective duration of the contingency reserve and strategic reserve portfolios at December 31, 2019, were 1.83 years, and 3.21 years, respectively, which are within the required durations per the policy.

The effective duration of the externally managed portfolio of the Municipal Central Treasury working capital portfolio at December 31, 2018, was 1.37 years, which is not within the targeted duration of +/-.25 years of the Merrill Lynch 90-day Treasury Bill Index, as required per Alaska Permanent Capital Management Investment Manager Agreement. The effective duration of the contingency reserve and strategic reserve portfolios at December 31, 2018, were 1.83 years, and 3.12 years, respectively, which are within the required durations per the policy.

The Beluga River Asset Retirement Obligation Fund does not have Investment Policies addressing interest rate risk.

Cash and Investments, continued

(d) Credit Risk

Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. For fixed income securities, this risk is generally expressed as a credit rating.

At December 31, 2019, the Municipal Central Treasury's investment in marketable debt securities, excluding U.S. Treasuries, totaled $248,214,420. The distribution of ratings on these securities was as follows:

Moody's		S&P	
Aaa	34%	AAA	7%
Aa	3%	AA	22%
A	16%	A	15%
Baa	16%	BBB	19%
Ba or Lower	20%	BB or Lower	19%
Not Rated	11%	Not Rated	18%
	100%		100%

At December 31, 2018, the Municipal Central Treasury's investment in marketable debt securities, excluding U.S. Treasuries and Agencies, totaled $185,136,594. The distribution of ratings on these securities was as follows:

Moody's		S&P	
Aaa	13%	AAA	11%
Aa	11%	AA	6%
A	22%	A	25%
Baa	26%	BBB	30%
Ba or Lower	24%	BB or Lower	22%
Not Rated	4%	Not Rated	6%
	100%		100%

Cash and Investments, continued

Credit Risk, continued

At December 31, 2019 and 2018, the Beluga River Asset Retirement Obligation Fund investment in fixed income securities, excluding U.S. Treasuries, totaled $4,900,063 and $5,015,367, respectively. The distribution of Moody's ratings on these securities was as follows:

Moody's Rating	2019	2018
Aaa	0%	2%
Aa	5%	2%
A	26%	28%
Baa	15%	19%
Not Rated	54%	49%
	100%	100%

(e) *Concentration of Credit Risk*

Concentration of credit risk is the risk of loss attributed to the magnitude of an entity's investment in a single issuer. GASB Statement No. 40 requires disclosure when the amount invested in a single issuer exceeds 5 percent or more of total investments. Investments issued or explicitly guaranteed by the U.S. Government, as well as mutual funds and other pooled investments, are exempted from this requirement. At December 31, 2019, the Municipal Cash Pool held investments in the Federal Farm Credit Bank that were 6.57 percent of the Municipal Cash Pool's investments.

The Beluga River Asset Retirement Obligation Fund has no policy regarding concentration of holdings with a single issuer.

At December 31, 2019, more than 5 percent of the Beluga River Asset Retirement Obligation Fund's investments were held with the Federal Home Loan Mortgage Corporation and Federal National Mortgage Association. These investments are 7.06 percent and 9.01 percent, respectively, of the Beluga River Asset Retirement Obligation Fund's total investments. At December 31, 2018, more than 5 percent of the Beluga River Asset Retirement Obligation Fund's investments were held with the Federal Home Loan Mortgage Corporation and Federal National Mortgage Association. These investments are 8.18 percent and 9.32 percent, respectively, of the Beluga River Asset Retirement Obligation Fund's total investments.

Cash and Investments, continued

(f) Custodial Credit Risk

Custodial credit risk is the risk, in event of the failure of a depository institution, that an entity will not be able to recover deposits or collateral securities in the possession of an outside party. For investments, custodial credit risk is the risk, in event of the failure of the counterparty to a transaction, that an entity will not be able to recover the value of the investment or collateral securities in the possession of an outside party. All collateral consists of obligations issued, or fully insured or guaranteed as to payment of principal and interest, by the United States of America, an agency thereof or a United States government sponsored corporation, with market value not less than the collateralized deposit balances.

AMC 6.50.030 requires that repurchase agreements be secured by obligations of the U.S. government, U.S. agencies, or U.S. government-sponsored corporations and agencies. As of December 31, 2019 and 2018 cash deposits and investments were not exposed to custodial credit risk.

(g) Foreign Currency Risk

Foreign currency risk is the risk that changes in exchange rates will adversely impact the fair value of an investment. The Municipality has no specific policy addressing foreign currency risk; however foreign currency risk is managed through the requirements of AMC 6.50.030 and the asset allocation policies of each portfolio.

The Municipal Central Treasury is not exposed to foreign currency risk because AMC 6.50.030 explicitly prohibits the purchase of securities not denominated in U.S. Dollars. At December 31, 2019 and 2018, all debt obligations held in the Municipal Central Treasury were payable in U.S. Dollars.

The Asset Retirement Obligation Fund invests in dollar denominated exchange traded international equity funds which are broadly diversified across currencies, effectively limiting foreign currency risk.

Cash and Investments, continued

(h) Fair Value Measurements

At December 31, 2019 and 2018, the Municipality had investments valued as follows:

- Asset-backed securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Short-term collective investments such as money market funds are valued at amortized cost.
- Commercial paper is valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Corporate bonds are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Domestic equity funds are valued at the closing price reported on the active market on which the individual funds traded.
- International equity funds are valued at the closing price reported on the active market on which the individual funds traded.
- Municipal bonds are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Real estate funds are valued at the closing price reported on the active market on which the individual funds traded.
- Repurchase agreements are valued at amortized cost.
- U.S Treasuries are valued at the closing price reported on the active market on which the individual securities traded.
- U.S Agencies are valued using pricing models maximizing the use of observable inputs for similar securities.
- U.S TIPs are valued at the closing price reported on the active market on which the individual securities traded.

Cash and Investments, continued

Fair Value Measurements, continued

The Municipality utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Municipality determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: quoted prices for identical assets or liabilities in active markets
- Level 2 Inputs: quoted prices for similar assets or liabilities in active or inactive markets; or inputs other than quoted prices that are observable
- Level 3 Inputs: significant unobservable inputs for assets or liabilities

The Municipality categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Municipality as a whole has the following recurring fair value measurements as of December 31, 2019 and 2018:

December 31, 2019:

		Fair Value Measurements Using	
Investment Type:	December 31, 2019	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
Central Treasury- Unrestricted			
Investments Measured at Fair Value:			
Commercial Paper	$ 2,824,608	$ -	$ 2,824,608
U.S. Treasuries	90,725,434	90,725,434	-
U.S. TIPS	4,133,704	4,133,704	-
U.S. Agencies	54,795,702	-	54,795,702
Municipal Bonds	58,119	-	58,119
Asset-Backed Securities	24,545,951	-	24,545,951
Corporate Fixed Income Securities	119,800,517	-	119,800,517
Domestic Equities	38,448	38,448	-
	$ 296,922,483	$ 94,897,586	$ 202,024,897
Investments Measured at Amortized Cost:			
Money Market Funds	$ 14,721,342		
Repurchase Agreements	61,467,262		
Total Central Treasury- Unrestricted	$ 373,111,087		

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Notes to Financial Statements

December 31, 2019 and 2018

Cash and Investments, continued

Fair Value Measurements, continued

December 31, 2019, continued:

Investment Type:	December 31, 2019	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Fair Value Measurements Using: Significant Other Observable Inputs (Level 2)
Central Treasury- Restricted			
Investments Measured at Fair Value:			
Commercial Paper	$ 468,305	$ -	$ 468,305
U.S. Treasuries	34,608,937	34,608,937	-
U.S. TIPS	685,346	685,346	-
U.S. Agencies	25,072,613	-	25,072,613
Municipal Bonds	9,636	-	9,636
Asset-Backed Securities	4,069,589	-	4,069,589
Corporate Fixed Income Securities	19,862,293	-	19,862,293
Domestic Equities	6,375	6,375	-
	$ 84,783,094	$ 35,300,658	$ 49,482,436
Investments Measured at Amortized Cost:			
Money Market Funds	$ 22,921,889		
Repurchase Agreements	10,190,948		
Total Central Treasury- Restricted	$ 117,895,931		
Asset Retirement Obligation Fund			
Investments Measured at Fair Value:			
U.S. Treasuries	$ 5,554,268	$ 5,554,268	$ -
Asset-Backed Securities	2,626,852	-	2,626,852
Corporate Fixed Income Securities	2,273,211	-	2,273,211
U.S. TIPS	1,608,253	1,608,253	-
Domestic Equity Funds	2,505,196	2,505,197	-
International Equity Funds	863,848	863,848	-
Real Estate Funds	824,588	524,588	-
	$ 16,256,216	$ 11,056,154	$ 4,900,063
Investments Measured at Amortized Cost:			
Money Market Funds	$ 86,590		
Total Asset Retirement Obligation Fund	$ 16,342,806		

Cash and Investments, continued

Fair Value Measurements, continued

December 31, 2018:

Investment Type:	December 31, 2018	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
Central Treasury - Unrestricted			
Investments Measured at Fair Value:			
U.S. Treasuries	$ 148,917,831	$ 103,429,738	$ 45,488,093
U.S. Agencies	20,351,315	-	20,351,315
Asset-Backed Securities	25,781,328	-	25,781,328
Corporate Securities	136,435,070	-	136,435,070
	$ 331,485,544	$ 103,429,738	$ 228,055,806
Investments Measured at Amortized Cost:			
Money Market Funds	$ 21,308,292		
Repurchase Agreements	22,398,105		
Total Central Treasury - Unrestricted	$ 375,191,941		
Central Treasury - Restricted			
Investments Measured at Fair Value:			
U.S. Treasuries	$ 34,914,468	$ 28,487,275	$ 6,427,193
U.S. Agencies	21,222,562	-	21,222,562
Asset-Backed Securities	3,642,746	-	3,642,746
Corporate Fixed Income Securities	19,277,450	-	19,277,450
	$ 79,057,226	$ 28,487,275	$ 50,569,951
Investments Measured at Amortized Cost:			
Money Market Funds	$ 22,072,465		
Repurchase Agreements	3,164,717		
Total Central Treasury - Restricted	$ 104,294,408		
Beluga River Asset Retirement Obligation Fund			
Investments Measured at Fair Value:			
U.S. Treasuries	$ 4,096,390	$ 4,096,390	$ -
Asset-Backed Securities	2,536,983	-	2,536,983
Corporate Fixed Income Securities	2,478,383	-	2,478,383
U.S. TIPS	1,360,928	1,360,928	-
Domestic Equity Funds	2,061,138	2,061,138	-
International Equity Funds	653,859	653,859	-
Real Estate Funds	642,504	642,504	-
	$ 13,830,185	$ 8,814,819	$ 5,015,366
Investments Measured at Amortized Cost:			
Money Market Funds	$ 85,668		
Total Asset Retirement Obligation Fund	$ 13,915,853		

(4) Capital Assets

A summary of capital assets at December 31, 2019 follows:

	January 1, 2019	Additions	Deductions	December 31, 2019
Electric plant in service	$ 998,082,203	$ 13,258,809	$ (6,124,834)	$ 1,005,216,178
Less accumulated depreciation	283,371,643	29,727,833	(7,084,035)	306,015,441
Net electric plant in service	714,710,560	(16,469,024)	959,201	699,200,737
Natural gas production and gathering plant	346,454,777	7,564,775	-	354,019,552
Less accumulated depletion	201,481,664	14,288,925	(7,516,022)	208,254,567
Net gas plant in service	144,973,113	(6,724,150)	7,516,022	145,764,985
Net electric and gas plant in service	859,683,673	(23,193,174)	8,475,223	844,965,722
Intangible plant, less accumulated amortization of $12,872,325 in 2019 and $12,767,052 in 2018	2,505,175	-	(105,272)	2,399,903
Construction work in progress	14,902,285	30,159,534	(15,094,034)	29,967,785
Total capital assets, net	$ 877,091,133	$ 6,966,360	$ (6,724,083)	$ 877,333,410

Included in the Construction Work in Progress are retirement assets as follows:

	$ 1,025,887	$ 1,152,350	$ (1,040,481)	$ 1,137,756

1. In accordance with the requirements of FERC, disposals of retirement assets are not placed in service, rather they are reported as deductions from accumulated depreciation.

Capital Assets, continued

A summary of capital assets at December 31, 2018 follows:

	January 1, 2018	Additions	Deductions	December 31, 2018
Electric plant in service	$ 975,077,993	$ 30,377,787	$ (7,373,577)	$ 998,082,203
Less accumulated depreciation	261,683,609	31,937,280	(10,249,246)	283,371,643
Net electric plant in service	713,394,384	(1,559,493)	2,875,669	714,710,560
Natural gas production and gathering plant	345,231,780	1,222,997	-	346,454,777
Less accumulated depletion	194,387,360	7,094,304	-	201,481,664
Net gas plant in service	150,844,420	(5,871,307)	-	144,973,113
Net electric and gas plant in service	864,238,804	(7,430,800)	2,875,669	859,683,673
Intangible plant, less accumulated amortization of $12,767,052 in 2018 and $12,661,781 in 2017	2,610,447	-	(105,272)	2,505,175
Construction work in progress	22,957,440	23,162,877	(31,218,032)	14,902,285
Total capital assets, net	$ 889,806,691	$ 15,732,077	$ (28,447,635)	$ 877,091,133

Included in the Construction Work in Progress are retirement assets as follows:

$ 768,992	$ 1,097,142	$ (840,247)	$ 1,025,887

In accordance with the requirements of FERC, disposals of retirement assets are not placed in service, rather they are reported as deductions from accumulated depreciation.

(5) Long-Term Liabilities

(a) Revenue Bonds Payable

A summary of revenue bonds payable consist of the following at December 31:

	2019	2018
Revenue bonds:		
2005 Series A, effective interest rate at 4.993858% due 2026	$ 10,870,000	$ 12,150,000
2009 Series A, effective interest rate at 5.009% due 2039	12,680,000	15,240,000
2009 Series B, effective interest rate at 5.009% due 2039 taxable	114,760,000	114,760,000
2014 Series A, effective interest rate at 3.81% due 2044	169,465,000	173,355,000
	307,775,000	315,505,000
Unamortized discount	(415,811)	(446,018)
Unamortized premium	16,247,046	17,436,399
	$ 323,606,235	$ 332,495,381

Long-Term Liabilities, continued

Revenue Bonds Payable, continued

Debt service requirements to maturity at December 31, 2019 are as follows:

	Senior Lien Electric Revenue Bonds		
	Principal	Interest	Total
2020	$ 8,075,000	$ 16,603,147	$ 24,678,147
2021	8,410,000	16,268,347	24,678,347
2022	8,760,000	15,917,897	24,677,897
2023	9,200,000	15,479,897	24,679,897
2024	9,635,000	15,042,772	24,677,772
2025 - 2029	55,420,000	66,936,195	122,356,195
2030 - 2034	69,545,000	49,398,028	118,943,028
2035 - 2039	87,430,000	27,022,900	114,452,900
2040 - 2044	51,300,000	6,625,600	57,925,600
Senior lien revenue bonds payable	$ 307,775,000	$ 229,294,783	$ 537,069,783

The Utility's revenue bonds bear interest at effective rates of 3.75% to 6.5% and require the establishment of reserves over a five-year period at least equal to the maximum annual debt service on all outstanding senior lien bonds. The senior lien revenue bond covenants further stipulate that net revenue before depreciation and amortization for each year will be equal to at least 1.35 times the debt service requirements for that year. At December 31, 2019 and 2018, the Utility had satisfied the reserve requirements and debt service covenants. The Utility has pledged future customer revenues, net of specified operating expenses, to repay revenue bonds. Proceeds from the bonds provided financing for construction and other capital improvements. The bonds are payable solely from customer net revenues and are payable through 2044. The total principal remaining and interest to be paid on the bonds for the years ended December 31, 2019 and 2018 was $537,069,783 and $561,750,529, respectively. Principal and interest paid for the years ended December 31, 2019 and 2018 were $24,680,747 and $25,178,098, respectively. Total customer net revenues for the years ended December 31, 2019 and 2018 were $62,569,791 and $62,308,872, respectively.

As a condition of the sale of the Utility, (See Note 13) the Municipality is obligated, under its Charter, to retire all debt of the Utility. Therefore, on the closing date of the sale, the Municipality i) will retire all outstanding 2005 Revenue Bonds, ii) will retire all outstanding 2009 Revenue Bonds, iii) will defease all outstanding 2014 Revenue Bonds to their maturity date or the first call date of December 1, 2024, whichever occurs first.

(b) Notes from Direct Borrowings

In February 2012, the Assembly authorized the issuance of commercial paper in one or more series in the aggregate principal amount not to exceed three hundred million dollars ($300,000,000). In April 2015, the Utility redeemed all outstanding commercial paper and entered into a short-term borrowing agreement with Wells Fargo Municipal Capital Strategies, LLC, herein referred to as the Direct Drawdown Purchase Program (DDPP).

Long-Term Liabilities, continued

Notes from Direct Borrowings, continued

This borrowing program continued to fulfill the purpose of the Commercial Paper program, but at a lower aggregate fee and interest cost to the Utility over the life of the program. The DDPP was used by the Utility to complete construction of Generation Plant 2A. At December 31, 2019 and 2018 the outstanding balance of DDPP notes payable was $191,900,000. On November 1, 2019 the loan term was extended to September 30, 2020. No further drawdowns are anticipated. The Utility intends to extend the loan term until December 31, 2020. Pursuant to the sale of the Utility, the Municipality will retire the amount outstanding on the date of the sale.

The maturity date of the loan is September 30, 2020. The Utility agrees to pay the outstanding principal and the accrued and unpaid interest on the earlier of the Termination date or the Maturity date. The interest rate is the LIBOR index rate as defined by the loan agreement. The average interest rate for 2019 was 2.77%.

In the event of default by the Utility, the Lender may terminate the Loan commitment and declare all amounts owed to be immediately due and payable. There are no unused lines of credit or assets pledged as collateral for this debt.

The following is a summary of long-term liability activity as of December 31, 2019 and 2018:

	Balance January 1, 2019	Additions	Reductions	Balance December 31, 2019	Due within one year
Revenue bonds payable:					
Series 2005A	$ 12,150,000	$ -	$ 1,280,000	$ 10,870,000	$ 1,340,000
Series 2009A	15,240,000	-	2,560,000	12,680,000	2,680,000
Series 2009B	114,760,000	-	-	114,760,000	-
Series 2014A	173,355,000	-	3,890,000	169,465,000	4,055,000
Senior electric revenue bonds	315,505,000	-	7,730,000	307,775,000	8,075,000
Unamortized premiums/discounts	16,990,381	-	1,159,146	15,831,235	-
Total revenue bonds payable	332,495,381	-	8,889,146	323,606,235	8,075,000
Notes from direct borrowings	191,900,000	-	-	191,900,000	191,900,000
Compensated absences payable	2,526,423	1,775,041	1,914,202	2,387,262	2,387,262
Net pension liability	11,361,736	-	1,267,144	10,094,592	-
Net OPEB liability	2,328,332	-	2,075,657	252,675	-
Asset retirement obligation	16,543,712	7,788,835	-	24,332,547	-
Total long term liabilities	$ 557,155,584	$ 9,563,876	$ 14,146,149	$ 552,573,311	$ 202,362,262

Long-Term Liabilities, continued

	Balance January 1, 2018 *	Additions	Reductions	Balance December 31, 2018	Due within one year
Revenue bonds payable:					
Series 2005A	$ 17,565,000	$ -	$ 5,415,000	$ 12,150,000	$ 1,280,000
Series 2009A	15,240,000	-	-	15,240,000	2,560,000
Series 2009B	114,760,000	-	-	114,760,000	-
Series 2014A	175,805,000	-	2,450,000	173,355,000	3,890,000
Senior electric revenue bonds	323,370,000	-	7,865,000	315,505,000	7,730,000
Unamortized premiums/discounts	18,244,927	-	1,254,546	16,990,381	-
Total revenue bonds payable	341,614,927	-	9,119,546	332,495,381	7,730,000
Notes from direct borrowings	191,900,000	-	-	191,900,000	-
Compensated absences payable	2,812,140	1,622,046	1,907,763	2,526,423	2,526,423
Net pension liability	12,270,893	-	909,157	11,361,736	-
Net OPEB liability	1,839,038 *	489,294	-	2,328,332	-
Asset retirement obligation	15,823,732	719,980	-	16,543,712	-
Total long term liabilities	$ 566,260,730	$ 2,831,320	$ 11,936,466	$ 557,155,584	$ 10,256,423

* Per implementation of GASB Statement No. 75, the Utility restated beginning balances for net OPEB Liability.

(6) Net Position

Net position is composed of the following at December 31:

	2019	2018
Total plant	$ 877,333,410	$ 877,091,133
Less: Total revenue bonds payable	(323,606,235)	(332,495,381)
Contributions in aid of construction	(172,546,886)	(177,823,955)
Notes payable	(191,900,000)	(191,900,000)
Bond proceeds used for bond reserve fund	24,394,998	24,046,945
Bond proceeds used for bond sale costs	1,235,426	1,337,730
Deferred loss on refunding	24,588	61,057
Net investment in capital assets	214,935,301	200,317,529
Debt service account	2,056,512	2,058,443
Revenue bond reserve investments	24,387,434	23,718,574
Less: Bond proceeds used for bond reserve fund	(24,394,998)	(24,046,945)
Accrued bond interest payable	(1,722,475)	(1,813,590)
Adjustment	-	83,518
Restricted for debt service	326,473	-
Operating reserve -		
Restricted for operations	14,391,000	15,206,000
Unrestricted	69,669,139	69,716,192
Total net position	$ 299,321,913	$ 285,239,721

(7) Retirement and OPEB Plans

Substantially all regular employees of the Utility are covered by one or more of the following plans:

(a) IBEW Plans

Defined Benefit Plan

The Utility's IBEW members participate in a cost-sharing defined benefit plan, *the Alaska Electrical Pension Plan of the Alaska Electrical Pension Fund* (IBEW Plan). The Alaska Electrical Trust Funds (AETF) Board of Trustees administers the IBEW Plan and has the authority to establish and amend benefit terms and approve changes in employer required contributions. Each year, AETF issues annual financial reports that can be obtained by writing the plan administrator, Alaska Electrical Pension Trust, 2600 Denali Street, Suite 200, Anchorage, Alaska, 99503. The Utility had 168 and 166 employees covered by the Plan as of December 31, 2019 and 2018, respectively.

The IBEW Plan provides several levels of retirement benefits, including early retirement, normal retirement, late retirement, and disability retirement and includes several options for spouse participation and death benefits. The Utility contributes to the IBEW Plan for its covered employees according to the terms of its Agreement Covering Terms and Conditions of Employment (Agreement) with the IBEW Local 1547. The Agreement in effect during 2018 and 2019 was effective until December 31, 2019. On February 27, 2020, the Agreement was extended to December 31, 2020 and amended effective the first full pay period in 2020.

Employer contributions are determined from hours of work reported by participating employers and the contractual employer contribution rate in effect. The Utility's required contribution to the IBEW Plan for each hour for which compensation is paid to the employee for January 1, 2019 to December 31, 2019 was $8.00 per hour, and from January 1, 2018 to December 31, 2018 was $7.95 per hour. The Utility's total employer contributions to the IBEW Plan for 2019 and 2018 were $3,249,636 and $3,382,920, respectively. The Utility had $355,339 and $119,769 in required contributions to the IBEW Plan payable to AETF at December 31, 2019 and 2018, respectively. These amounts are paid during the normal course of business in the month following each year end. The Utility is not subject to withdrawal penalties, nor are there any future minimum payments to the IBEW Plan required other than the contribution per hour compensated as required by the Agreement.

Defined Contribution Plan - Money Purchase Plan

The Agreement requires employer contributions to be made in an amount of 1.9% of each employee's gross wages to the Alaska Electrical Workers Money Purchase Plan (Money Purchase Plan). The Utility's employer and employee contributions to the Money Purchase Plan during 2019 were $412,735 and $106,142, respectively. The Utility's employer and employee contributions to the Money Purchase Plan during 2018 were $437,345 and $89,841, respectively. One hundred percent (100%) of the Utility's required contributions to the IBEW plans have been made through these contributions to the AETF.

Retirement and OPEB Plans, continued

(b) State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III)

General Information About the Plan

The Municipality participates in the Alaska Public Employees' Retirement System (PERS I-III or the Plan). PERS I-III is a cost-sharing multiple employer plan which covers eligible State and local government employees, other than teachers. The Plan was established and is administered by the State of Alaska Department of Administration. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

The Plan provides for retirement, death and disability, and post-employment health care benefits. There are three tiers of employees, based on entry date. For all tiers within the Defined Benefit (DB) plan, full retirement benefits are generally calculated using a formula comprised of a multiplier times the average monthly salary (AMS) times the number of years of service. The multiplier is increased at longevity milestone markers for most employees.

The tiers within the Plan establish differing criteria regarding normal retirement age, early retirement age, and the criteria for calculation of AMS, COLA adjustments, and Other Post-Employment Benefits (OPEB) benefits.

A complete benefit comparison chart is available at the website noted below.

The Plan is included in a comprehensive annual financial report that includes financial statements and other required supplemental information. That report is available via the internet at http://doa.alaska.gov/drb/pers. Actuarial valuation reports, audited financial statements, and other detailed plan information are also available on this website. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811-0203 or by phoning (907) 465-4460.

The PERS I-III DB Plan was closed to new entrants effective July 1, 2006. New employees hired after that date participate in the PERS IV Defined Contribution (DC) Plan described later in this note.

Historical Context and Special Funding Situation

In April 2008, the Alaska Legislature passed legislation converting the previously existing PERS plan from an agent-multiple employer plan to a defined benefit cost-sharing plan with an effective date of July 1, 2008. In connection with this conversion, the State of Alaska passed additional legislation which statutorily capped the employer contribution rate, established a state funded "on-behalf" contribution (subject to funding availability), and required that employer contributions be calculated against all PERS eligible wages, including wages paid to participants of the PERS Tier IV defined contribution plan described later in this note.

Alaska Statutes require the State of Alaska to contribute to the Plan an amount such that, when combined with the employer contribution, is sufficient to pay the Plan's past service liability contribution rate as adopted by the Alaska Retirement Management Board.

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

Although current statutes call for the State of Alaska to contribute to the Plan, the Alaska Department of Law determined that the statute does not create a legal obligation to assume the liabilities of the Plan; rather it establishes a contribution mechanism to provide employer relief against the rising contribution rates. This relief payment is subject to funding availability, and therefore not legally mandated. As a result, the State initially determined that the Plan is not in a special funding situation. Following much discussion with various stakeholders, participant communities, attorneys, auditors, and the GASB itself, the State has subsequently reversed its position on this matter, and as of June 30, 2015, the State did record the liability presuming that the current statute does constitute a special funding situation as the legislation is currently written. It is important to note that the Alaska Legislature has the power and authority to change the aforementioned statute through the legislative process, and it is likely that the State will pursue efforts to do so in a future legislative session.

For the current year financial statements, management has treated AS 39.35.255 and AS 39.35.280 as constituting a special funding situation under GASB Statement No. 68 rules and has recorded all pension related liabilities, deferred inflows and outflows of resources, and disclosures on this basis.

Employee Contribution Rates
Regular employees are required to contribute 6.75 percent of their annual covered salary.

Employer and Other Contribution Rates
There are several contribution rates associated with the pension and healthcare contributions and related liabilities. These amounts are calculated on an annual basis.

Employer Effective Rate
This is the contractual employer pay-in rate. Under current legislation, this rate is statutorily capped at 22 percent of eligible wages, subject to a wage floor, and other termination events. This 22 percent rate is calculated on all PERS participating wages, including those wages attributable to employees in the defined contribution plan. Contributions derived from the defined contribution employees are referred to as the Defined Benefit Unfunded Liability (DBUL) contribution.

Alaska Retirement Management (ARM) Board Adopted Rate
This is the rate formally adopted by the ARM Board. This rate is actuarially determined and used to calculate annual Plan funding requirements, without regard to the statutory rate cap or the GASB accounting rate. Prior to July 1, 2015, there were no constraints or restrictions on the actuarial cost method or other assumptions used in the ARM Board valuation. Effective July 1, 2015, the Legislature requires the ARM Board to adopt employer contribution rates for past service liabilities using a level percent of pay method over a closed 25 year term which ends in 2039.

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

On-behalf Contribution Rate

This is the rate paid in by the State as an on-behalf payment under the current statute. The statute requires the State to contribute, based on funding availability, an on-behalf amount equal to the difference between the ARM Board Rate and the Employer Effective Rate. In the Utility's financial statements, the on-behalf amounts reflect revenue and expense only during the measurement period July 1, 2018 to June 30, 2019, in which the Plan recognizes the payments, resulting in a significant timing difference between the cash transfers and revenue and expense recognition. Total on-behalf amounts recognized as of the measurement period are actuarially calculated.

Contribution rates for the years ended June 30, 2018 and June 30, 2019 were determined in the June 30, 2017 and June 30, 2018 actuarial valuations, respectively. Municipality contribution rates for the 2019 and 2018 calendar year were as follows:

January 1, 2019 to June 30, 2019	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate
Pension	16.17%	23.21%	5.58%
Postemployment Healthcare (ARHCT) (see Note 7)	5.83%	4.37%	0.00%
Total Contribution Rates	22.00%	27.58%	5.58%

July 1, 2019 to December 31, 2019	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate
Pension	15.72%	23.73%	6.62%
Postemployment Healthcare (ARHCT) (see Note 7)	6.28%	4.89%	0.00%
Total Contribution Rates	22.00%	28.62%	6.62%

January 1, 2018 to June 30, 2018	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	17.12%	21.90%	3.01%	29.07%
Postemployment healthcare (ARHCT) (see Note 7)	4.88%	3.11%	0.00%	66.85%
Total Contribution Rates	22.00%	25.01%	3.01%	95.92%

July 1, 2018 to December 31, 2018	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	16.17%	23.21%	5.58%	32.11%
Postemployment healthcare (ARHCT) (see Note 7)	5.83%	4.37%	0.00%	87.90%
Total Contribution Rates	22.00%	27.58%	5.58%	120.01%

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

In 2019 and 2018, the Utility's proportionate share of the Municipality's share was 2.85 and 3.14 percent, respectively and was credited with the following contributions into the pension plan.

	Measurement Period	Utility's Fiscal Year	Measurement Period	Utility's Fiscal Year
	July 1, 2018 to June 30, 2019	January 1, 2019 to December 31, 2019	July 1, 2017 to June 30, 2018	January 1, 2018 to December 31, 2018
Employer contributions (including DBUL)	$ 822,902	$ 804,904	$ 968,982	$ 936,339
Nonemployer contributions (on-behalf)	375,628	398,678	225,603	323,645
Total Contributions	$ 1,198,530	$ 1,203,582	$ 1,194,585	$ 1,259,984

In addition, employee contributions to the Plan totaled $264,652 and $226,127 during the Utility's calendar years 2019 and 2018, respectively.

Pension Liabilities, Pension Expense, Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions

The Utility's portion of the Municipality's liabilities, pension expense, deferred outflows and inflows of resources related to pensions are based on its share of the Municipality's contributions to the plan in the current year. Those proportions are 2.85% and 3.14% at December 31, 2019 and 2018, respectively.

At December 31, 2019 and 2018, the Municipality reported a liability for its proportionate share of the net pension liability (NPL) that reflected a reduction for State pension support provided to the Municipality. The amount recognized by the Municipality and the Utility for their proportional share, the related State proportion, and the total were as follows:

December 31,	2019		2018	
	Municipality	Utility	Municipality	Utility
Proportionate Share of NPL	$ 353,891,460	$ 10,094,592	$ 361,285,220	$ 11,361,736
State's proportionate share of NPL associated with the Municipality	$ 140,522,422	$ 4,008,338	$ 104,636,568	$ 3,290,622
Total Pension Liability	$ 494,413,882	$ 14,102,930	$ 465,921,788	$ 14,652,358

The total pension liability for the June 30, 2019 measurement date was determined by an actuarial valuation as of June 30, 2018 rolled forward to June 30, 2019 to calculate the net pension liability as of that date. The total pension liability for the June 30, 2018 measurement date was determined by an actuarial valuation as of June 30, 2017 rolled forward to June 30, 2018 to calculate the net pension liability as of that date.

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

The Municipality's proportion of the net pension liability was based on a projection of the Municipality's long-term share of contributions to the pension plan relative to the projected contributions of all participating entities, including the State, actuarially determined. At the June 30, 2019 measurement date, the Utility's proportion was 0.1844 percent, which was a decrease of 0.0442 percent from the prior year. At the June 30, 2018 measurement date, the Utility's proportion was 0.2286 percent, which was an increase of 0.0087 percent from its proportion measured as of June 30, 2017.

The Utility recognized pension expense of $1,582,003 and $626,449 for the year ended December 31, 2019 and December 31, 2018, respectively, of which $544,512 and $154,073 were recorded as on-behalf revenue and expense for additional contributions paid by the State.

At December 31, 2019 and 2018, the Utility reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

	Measurement Period June 30, 2019		Measurement Period June 30, 2018	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (149,439)	$ -	$ (285,157)
Changes in assumptions	309,051	-	-	-
Net difference between projected and actual earnings on pension plan investments	144,735	-	250,929	-
Changes in proportion and differences between Utility contributions and proportionate share of contributions	-	(368,266)	412,990	-
Utility contributions subsequent to the measurement date	427,894	-	491,593	-
Total Deferred Outflows and Deferred Inflows Related to Pensions	$ 881,680	$ (517,705)	$ 1,155,512	$ (285,157)

At December 31, 2019, the $427,894 reported as deferred outflows of resources related to pensions resulting from contributions subsequent to the measurement date will be recognized as a reduction in the net pension liability in the year ended December 31, 2020. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Year Ending December 31,	Net Amortization of Deferred Outflows and Deferred Inflows of Resources
2020	$ (48,063)
2021	(106,860)
2022	41,065
2023	49,939
Total Amortization	$ (63,919)

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

Actuarial Assumptions

The total pension liability for the measurement period ended June 30, 2019 was determined by an actuarial valuation as of June 30, 2018, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2019. The actuarial assumptions used in the June 30, 2018 (latest available) actuarial valuation were based on the results of an actuarial experience study for the period from July 1, 2013 to June 30, 2017, resulting in changes in actuarial assumptions adopted by the ARM Board to better reflect expected future experience.

Inflation	2.50%
Actuarial Cost Method	Entry Age Normal- Level Percentage of Payroll
Allocation Methodology	Amounts for the June 30, 2019 measurement date were allocated to employers based on the present value of contributions for FY2021-FY2039, as determined by projections based on the June 30, 2018 valuation.
Salary Increases	For peace officers/firefighters, increases range from 7.75 percent to 2.75 percent, based on service. For all others, increases range from 6.75 percent to 2.75 percent, based on service.
Investment Return / Discount Rate	7.38 percent, net of pension plan investment expenses. This is based on an average inflation rate of 2.50 percent and real rate of return of 4.88 percent.
Mortality	Pre-termination and post-termination mortality rates were based upon the 2013-2017 actual mortality experience. Pre-termination mortality rates were based on 100% of the RP-2014 table with MP-2017 generational improvement. Post-terminiation mortality rates were based on 91% of male and 96% of female rates of the RP-2014 table with MP-2017 generational improvement. Deaths are assumed to be occupational 75% of the time for peace officer/firefighters, 40% of the time for all others.

The total pension liability for the measurement period ended June 30, 2018 was determined by an actuarial valuation as of June 30, 2017, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2018. The actuarial assumptions used in the June 30, 2017 actuarial valuation were based on the results of an actuarial experience study for the period from July 1, 2009 to June 30, 2013, resulting in changes in actuarial assumptions adopted by the Alaska Retirement Management Board to better reflect expected future experience.

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

Inflation	3.12%
Actuarial Cost Method	Entry Age Normal- Level Percentage of Payroll
Allocation Methodology	Amounts for the June 30, 2018 measurement date were allocated to employers based on the present value of contributions for FY2020-FY2039, as determined by projections based on the June 30, 2017 valuation.
Salary Increases	For peace officers/firefighters, increases range from 9.66 percent to 4.92 percent, based on service. For all others, increases range from 8.55 percent to 4.34 percent, based on age and service.
Investment Return / Discount Rate	8.00 percent, net of pension plan investment expenses. This is based on an average inflation rate of 3.12 percent and real rate of return of 4.88 percent.
Mortality (Pre-termination)	Based upon 2010-2013 actual mortality experience, 60% of male and 65% of female post-termination mortality rates. Deaths are assumed to be occupational 70% of the time for Peace Officers/Firefighters, 50% of the time for Others.
Mortality (Post-termination)	Based upon the 2010-2013 actual mortality experience. 96% of all rates of the RP-2000 table, 2000 Base Year projected to 2018 with Projection Scale BB.

Long-Term Expected Rate of Return

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class.

These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of the measurement period June 30, 2019 and 2018 are summarized in the following table (note that the rates shown below exclude the inflation component):

June 30, 2019

Asset Class	Long-term Expected Real Rate of Return	Target	Range
Broad domestic equity	8.16%	24%	+/- 6%
Global equity (non-U.S.)	7.51%	22%	+/- 4%
Intermediate treasuries	1.58%	10%	+/- 5%
Opportunistic	3.96%	10%	+/- 5%
Real assets	4.76%	17%	+/- 8%
Absolute return	4.76%	7%	+/- 4%
Private equity	11.39%	9%	+/- 5%
Cash equivalents	0.83%	1%	+3/-1%

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

June 30, 2018

Asset Class	Long-term Expected Real Rate of Return	Target	Range
Broad domestic equity	8.90%	24%	+/- 6%
Global equity (non-U.S.)	7.85%	22%	+/- 4%
Fixed income	1.25%	10%	+/- 5%
Opportunistic	4.76%	10%	+/- 5%
Real assets	6.20%	17%	+/- 8%
Absolute return	4.76%	7%	+/- 4%
Private equity	12.08%	9%	+/- 5%
Cash equivalents	0.66%	1%	+3/-1%

Discount Rate

The discount rate used to measure the total pension liability was 7.38 percent and 8 percent in 2019 and 2018, respectively. The projection of cash flows used to determine the discount rate assumed that Employer and State contributions will continue to follow the current funding policy which meets State statutes. Based on those assumptions, the pension plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Discount Rate Sensitivity

The following presents the Utility's proportionate share of the net pension liability calculated using the current discount rate of 7.38 percent and 8 percent for 2019 and 2018 respectively, as well as what the Utility's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

June 30, 2019

	Proportional Share	1% Decrease (6.38%)	Current Discount Rate (7.38%)	1% Increase (8.38%)
Utility's proportionate share of the net pension liability	0.018440%	$ 13,323,090	$ 10,094,592	$ 7,390,830

June 30, 2018

	Proportional Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utility's proportionate share of the net pension liability	0.022865%	$ 15,045,805	$ 11,361,736	$ 8,245,459

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III), continued

Pension Plan Fiduciary Net Position

Detailed information about the pension plan's fiduciary net position is available in the separately issued PERS financial report.

(c) State of Alaska Public Employees' Retirement System Defined Contribution Plan (PERS IV)

Plan Information

The Utility participates in the Alaska Public Employees' Retirement System (PERS IV or (Plan). PERS IV is a Defined Contribution (DC) plan which covers eligible State and local government employees, other than teachers. The Plan was established and is administered by the State of Alaska Department of Administration. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

The Plan is included in a comprehensive annual financial report that includes financial statements and other required supplemental information. That report is available via the internet at http://doa.alaska.gov/drb/pers. Actuarial valuation reports, audited financial statements, and other detailed plan information are also available on this website. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811-0203 or by phoning (907) 465-4460.

Plan Participation and Benefit Terms

The Plan is governed by Section 401(a) of the Internal Revenue Code. A portion of employee wages and a matching employer contributions are made to the Plan before tax. These contributions plus any change in value (interest, gains and losses), and minus any Plan administrative fees or other charges, are payable to the employee or the employee's beneficiary at a future date. The Plan is a participant-directed plan with investment options offered by providers that are selected by the ARM Board.

Participating employees are immediately and fully vested in that employee's contributions and related earnings (losses). An employee shall be full vested in the employer contributions made on that employee's behalf, and related earnings (losses), after five years of service. An employee is partially vested in the employer contributions, made on that employee's behalf, and the related earnings, in the ratio of (a) 25 percent with two years of service; (b) 50 percent with three years of service; (c) 75 percent with four years of service; and (d) 100 percent with five years of service. Employer contributions, and related earnings, that are contributed for employees that are not fully vested before leaving employment are considered forfeit and returned to the employer.

Employees first enrolling into PERS after July 1, 2006 participate in PERS IV. PERS IV is a defined contribution retirement plan that includes a component of defined benefit post-employment health care.

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Contribution Plan (PERS IV), continued

Plan Contribution Requirement

The Plan requires both employer and employee contributions. Employees may make additional contributions into the Plan, subject to limitations. Contribution rates for 2019 and 2018 are as follows:

	1/1 - 6/30	7/1 - 12/31
Employee Contribution	8.00%	8.00%
Employer Contribution		
Retirement	5.00%	5.00%

The Utility contributed $159,421 and $159,988 to PERS IV on behalf of its employees for the years ended December 31, 2019 and 2018, respectively. Employee contributions to the Plan totaled $254,649 and 256,006 for 2019 and 2018, respectively. Defined Contribution forfeitures for the Utility in 2019 were $49,654.

(d) State of Alaska Public Employees' Retirement System OPEB Plans

General Information About the Plans

As part of its participation in the PERS Defined Benefit Plan (Tiers I, II, III), which is a cost-sharing multiple employer plan, the Utility participates in the Alaska Retiree Healthcare Trust (ARHCT), Retiree Medical Plan (RMP) and Occupational Death and Disability Plan (ODD). The ARHCT is self-funded and provides major medical coverage to retirees of the Defined Benefit Plan. Benefits vary by Tier level. The ARHCT was closed to all new members effective July 1, 2006. The RMP provides major medical coverage to retirees of the PERS Defined Contribution Plan (Tier IV). The RMP is self-insured. Members are not eligible to use this plan until they have at least 10 years of service and are Medicare eligible. The ODD provides death benefits for beneficiaries of plan participants and long-term disability benefits to all active members within PERS. The Plans are administered by the State of Alaska, Department of Administration. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811-0203 or by phoning (907) 465-4460.

The Utility is required to contribute the following percentages of covered payroll into the OPEB plans; for January 1 through June 30, 2019, ARHCT 5.83 percent, ODD .26 percent, and RMP .94 percent, for July 1 through December 31, 2019, ARHCT 6.28 percent, ODD .26 percent, and RMP 1.32 percent. Employees do not contribute.

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

In 2019, the Utility was credited with the following contributions to the OPEB plan

	Measurement Period July 1, 2018 to June 30, 2019	Utility's Fiscal Year January 1, 2019 to December 31, 2019
Employer contributions- ARHCT	$ 296,622	$ 305,616
Employer contributions- RMP	28,464	36,182
Employer contributions- ODD	13,300	13,785
Total Contributions	$ 338,386	$ 355,584

The Utility is required to contribute the following percentages of covered payroll into the OPEB plans, January 1 through June 30, 2018 ARHCT, 4.88%, ODD, 0.43%, and RMP, 1.03%, for July 1 through December 31, 2018, ARHCT 5.83 percent, ODD .26 percent, and RMP .94 percent Employees do not contribute.

In 2018, the Utility was credited with the following contributions to the OPEB plans:

	Measurement Period July 1, 2017 to June 30, 2018	Utility's Fiscal Year January 1, 2018 to December 31, 2018
Employer contributions- ARHCT	$ 276,203	$ 303,957
Employer contributions- RMP	31,005	31,365
Employer contributions- ODD	7,635	11,425
Nonemployer contributions (on-behalf)	-	-
Total Contributions	$ 314,843	$ 346,747

OPEB Liabilities, OPEB Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB Plans

At December 31, 2019 and 2018, the Utility reported a liability for its proportionate share of the net OPEB liabilities (NOL) that reflected a reduction for State OPEB support provided to the Utility. The Utility reported a net OPEB asset (NOA) for ODD. The amount recognized by the Utility for its proportional share, the related State proportion, and the total were as follows:

	2019	2018
Utility's proportionate share of NOL- ARHCT	$ 273,600	$ 2,346,143
Utility's proportionate share of NOL- RMP	58,071	33,844
Utility's proportionate share of NOA - ODD	(78,996)	(51,655)
Utility's Net OPEB liability	$ 252,675	$ 2,328,332
State's proportionate share of ARHCT NOL associated with the Utility	108,789	681,062
Total Net OPEB Liabilities	$ 361,464	$ 3,009,394

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

The total OPEB liabilities for the June 30, 2019 measurement date was determined by an actuarial valuation as of June 30, 2018 rolled forward to June 30, 2019 to calculate the net OPEB liabilities as of that date. The Utility's proportion of the net OPEB liabilities were based on a projection of the Utility's long-term share of contributions to the OPEB plans relative to the projected contributions of all participating entities, actuarially determined. The Utility's proportionate share at the June 30, 2019 measurement date changed from the proportionate share as of the June 30, 2018, as shown below.

Utility's proportionate share of the net OPEB liabilities:	Measurement Date June 30, 2018	Measurement Date June 30, 2019	Change
ARHCT	0.22860%	0.18439%	-0.04421%
RMP	0.26596%	0.24273%	-0.02323%
ODD	0.26596%	0.32582%	0.05986%

The total OPEB liabilities for the June 30, 2018 measurement date was determined by an actuarial valuation as of June 30, 2017 rolled forward to June 30, 2018 to calculate the net OPEB liabilities as of that date. The Utility's proportion of the net OPEB liabilities were based on a projection of the Utility's long-term share of contributions to the OPEB plans relative to the projected contributions of all participating entities, actuarially determined. The Utility's proportionate share at the June 30, 2018 measurement date increased over the proportionate share as of the June 30, 2017, as shown below.

Utility's proportionate share of the net OPEB liabilities:	Measurement Date June 30, 2017	Measurement Date June 30, 2018	Change
ARHCT	0.22046%	0.22860%	0.00814%
RMP	0.25969%	0.26596%	0.00627%
ODD	0.25969%	0.26596%	0.00627%

As a result of its requirement to contribute to the Plans and changes in the actuarially calculated net OPEB asset and liability, the Utility recognized net OPEB expense of ($2,543,341) and $371,147 for 2019 and 2018, respectively, which includes ($703,104) and $89,409 of on-behalf expense. On-behalf revenue was recognized for ($703,104) and $89,409 for 2019 and 2018, respectively, for actuarially calculated support provided by the State for the ARHCT plan.

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

At December 31, 2019 and 2018, the Utility reported deferred outflows of resources and deferred inflows of resources related to all OPEB plans from the following sources:

	Measurement Period June 30, 2019		Measurement Period June 30, 2018	
All Plans	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (212,785)	$ -	$ (267,153)
Changes in assumptions	391,170	(1,511)	371,612	-
Net difference between projected and actual earnings on OPEB plan investments		(120,970)		(503,921)
Changes in proportion and differences between Utility contributions and proportionate share of contributions	53,108	(79,288)	171,440	(72,359)
Utility contributions subsequent to the measurement date	200,086	-	201,633	-
Total Deferred Outflows and Deferred Inflows of Resources Related to OPEB	$ 644,364	$ (414,554)	$ 744,685	$ (843,433)

Deferred outflows of resources and deferred inflows of resources from each Plan for 2019 are reported from the following sources:

	Measurement Period June 30, 2019	
ARHCT	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (183,853)
Changes in assumptions	363,063	-
Net difference between projected and actual earnings on OPEB plan investments	-	(119,807)
Changes in proportion and differences between Utility contributions and proportionate share of contributions	51,115	(68,820)
Utility contributions subsequent to the measurement date	169,707	-
Total Deferred Outflows and Deferred Inflows of Resources Related to ARHCT	$ 583,885	$ (372,480)

	Measurement Period June 30, 2019	
RMP	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (4,302)
Changes in assumptions	28,108	-
Net difference between projected and actual earnings on OPEB plan	-	(641)
Changes in proportion and differences between Utility contributions and proportionate share of contributions	1,993	-
Utility contributions subsequent to the measurement date	22,821	-
Total Deferred Outflows and Deferred Inflows of Resources Related to RMP	$ 52,922	$ (4,943)

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

	Measurement Period June 30, 2019	
ODD	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (24,630)
Changes in assumptions	-	(1,511)
Net difference between projected and actual earnings on OPEB plan	-	(522)
Changes in proportion and differences between Utility contributions and proportionate share of contributions	-	(10,469)
Utility contributions subsequent to the measurement date	7,558	-
Total Deferred Outflows and Deferred Inflows of Resources Related to ODD	$ 7,558	$ (37,131)

The $200,086 reported in 2019 as deferred outflows of resources related to OPEB resulting from contributions made subsequent to the measurement date will be recognized as a reduction in the net OPEB liability in the following year. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

All Plans Year Ending December 31,	Net Amortization of Deferred Outflows and Deferred Inflows of Resources
2020	$ 65,446
2021	(96,058)
2022	28,150
2023	36,930
2024	(1,516)
Thereafter	(3,228)
Total Amortization	$ 29,724

Excluding contributions made subsequent to the measurement date, other amounts reported as deferred outflows of resources and deferred inflows of resources related to each OPEB plan will be recognized in OPEB expense as follows:

ARHCT Year Ending December 31,	Net Amortization of Deferred Outflows and Deferred Inflows of Resources
2020	$ 68,382
2021	(93,124)
2022	28,824
2023	37,616
Total Amortization	$ 41,698

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

RMP Year Ending December 31,	Net Amortization of Deferred Outflows and Deferred Inflows of Resources	
2020	$	2,706
2021		2,706
2022		4,245
2023		4,217
2024		3,629
Thereafter		7,655
Total Amortization	$	25,158

ODD Year Ending December 31,	Net Amortization of Deferred Outflows and Deferred Inflows of Resources	
2020	$	(5,642)
2021		(5,642)
2022		(4,918)
2023		(4,903)
2024		(5,145)
Thereafter		(10,882)
Total Amortization	$	(37,132)

Actuarial Assumptions

The total OPEB liability for the measurement period ended June 30, 2019 was determined by an actuarial valuation as of June 30, 2018, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2019. The actuarial assumptions used in the June 30, 2018 actuarial valuation were based on the results of an actuarial experience study for the period from July 1, 2013 to June 30, 2017, resulting in changes in actuarial assumptions adopted by the ARM Board to better reflect expected future experience.

In addition to the changes in assumptions resulting from the experience study, the following changes have been made since the prior valuation:

- An Employee Group Waiver Plan (EGWP) was implemented effective January 1, 2019. This arrangement replaced the Retiree Drug Subsidy (RDS) under Medicare Part D and resulted in larger projected subsidies to offset the cost of prescription drug coverage.
- Based on recent experience, the healthcare cost trend assumptions were updated.
- Per capita claims costs were updated to reflect recent experience.
- Healthcare cost trends were updated to reflect a Cadillac Tax load.

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

Actuarial cost method	Entry age normal; level percentage of payroll
Amortization method	Level dollar, closed
Inflation	2.50%
Salary Increases	Graded by service from 7.75 percent to 2.75 percent, for peace officers/firefighters. Graded by service from 6.75 percent to 2.75 percent, for all others.
Allocation methodology	Amounts for the June 30, 2018 measurement date were allocated to employers based on the projected present value of contributions for FY2020-FY2039. The liability is expected to go to zero at 2039.
Investment Return / Discount Rate	7.38 percent, net of postemployment healthcare plan investment expenses. This is based on an average inflation rate of 2.50 percent and real rate of return of 4.88 percent.
Healthcare cost trend rates	Pre-65 medical; 7.5 percent grading down to 4.5 percent Post-65 medical; 5.5 percent grading down to 4.5 percent Prescripion drug; 8.5 percent grading down to 4.5 percent EGWP: 8.5 percent grading down to 4.5 percent
Mortality	Pre-termination and post-termination mortality rates were based upon the 2013-2017 actual mortality experience. Post-termination mortality rates were based on 91% of the male rates and 96% of the female rates of the RP-2014 healthy annuitant table projected with MP-2017 generational improvement. The rates for pre-termination mortality were 100% of the RP-2014 employee table with MP-2017 generational improvement.
Participation (ARHCT)	100 percent system paid of members and their spouses are assumed to elect the healthcare benefits as soon as they are eligible. 10 percent of non-system paid members and their spouses are assumed to elect the healthcare benefits as soon as they are eligible.

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

The total OPEB liability for the measurement period ended June 30, 2018 was determined by an actuarial valuation as of June 30, 2017, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2018. The actuarial assumptions used in the June 30, 2017 actuarial valuation were based on the results of an actuarial experience study for the period from July 1, 2009 to June 30, 2013, resulting in changes in actuarial assumptions adopted by the ARM Board to better reflect expected future experience.

Actuarial cost method	Entry age normal; level percentage of payroll
Amortization method	Level dollar, closed
Inflation	3.12%
Salary Increases	Graded by service from 8.55 percent to 4.34 percent, for all others.
Allocation methodology	Amounts for the June 30, 2018 measurement date were allocated to employers based on the projected present value of contributions for FY2020-FY2039. The liability is expected to go to zero at 2039.
Investment Return / Discount Rate	8.00 percent, net of postemployment healthcare plan investment expenses. This is based on an average inflation rate of 3.12 percent and real rate of return of 4.88 percent.
Healthcare cost trend rates	Pre-65 medical; 8.0 percent grading down to 4.0 percent Post-65 medical; 5.5 percent grading down to 4.0 percent Prescripion drug; 9.0 percent grading down to 4.0 percent
Mortality (Pre-termination)	Based upon 2010-2013 actual mortality experience, 60% of male and 65% of female post-termination mortality rates. Deaths are assumed to be occupational 50% of the time for Others.
Mortality (Post-termination)	96% of all rates of the RP-2000 table, 2000 Base Year projected to 2018 with Projection Scale BB.

Long-Term Expected Rate of Return

The long-term expected rate of return on OPEB plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of postretirement healthcare plan investment expense and inflation) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The best estimates of arithmetic real rates of return for each major asset class are summarized in the following tables (note that the rates shown below exclude the inflation component):

June 30, 2019

Asset Class	Long-term Expected Real Rate of Return	Target	Range
Broad domestic equity	8.16%	24%	+/- 6%
Global equity (non-U.S.)	7.51%	22%	+/- 4%
Intermediate treasuries	1.58%	10%	+/- 5%
Opportunistic	3.96%	10%	+/- 5%
Real assets	4.76%	17%	+/- 8%
Absolute return	4.76%	7%	+/- 4%
Private equity	11.39%	9%	+/- 5%
Cash equivalents	0.83%	1%	+3/-1%

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

June 30, 2018

Asset Class	Long-term Expected Real Rate of Return	Target	Range
Broad domestic equity	8.90%	24%	+/- 6%
Global equity (non-U.S.)	7.85%	22%	+/- 4%
Fixed income	1.25%	10%	+/- 5%
Opportunistic	4.76%	10%	+/- 5%
Real assets	6.20%	17%	+/- 8%
Absolute return	4.76%	7%	+/- 5%
Private equity	12.08%	9%	+/- 5%
Cash equivalents	0.66%	1%	+3/-1%

Discount Rate

The discount rate used to measure the total OPEB liability in 2019 and 2018 was 7.38 percent and 8.00 percent, respectively for each plan. The projection of cash flows used to determine the discount rate assumed that employer and State contributions will continue to follow the current funding policy which meets State statutes. Based on those assumptions, the OPEB plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on OPEB plan investments was applied to all periods of projected benefit payments to determine the total OPEB liability for each plan.

Discount Rate Sensitivity

The following presents the Utility's proportionate share of the net OPEB liabilities calculated using the current discount rate for both years presented, as well as what the Utility's proportionate share of the net OPEB liabilities would be if they were calculated using a discount rate that is 1-percentage-point lower or 1-percentage-point higher than the current rate:

2019	Proportional Share	1% Decrease (6.38%)	Current Discount Rate (7.38%)	1% Increase (8.38%)
Utility's proportionate share of the NOL- ARHCT	0.18439%	$ 2,200,767	$ 273,600	$ (1,311,706)
Utility's proportionate share of the NOL- RMP	0.24273%	145,855	58,071	(8,017)
Utility's proportionate share of the NOA- ODD	0.32582%	(74,933)	(78,996)	(82,280)

2018	Proportional Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utillity's proportionate share of the NOL- ARHCT	0.22860%	$ 4,749,764	$ 2,346,143	$ 331,417
Utillity's proportionate share of the NOL- RMP	0.26596%	101,066	33,844	(18,588)
Utillity's proportionate share of the NOA- ODD	0.26596%	(48,506)	(51,655)	(54,246)

Retirement and OPEB Plans, continued

***State of Alaska Public Employees' Retirement System OPEB Plans*, continued**

Healthcare Cost Trend Rate Sensitivity

The following presents the Utility's proportionate share of the net OPEB liabilities as of June 30, 2019 and 2018, calculated using the healthcare cost trend rates as summarized in the 2019 and 2018 actuarial valuation report, respectively, as well as what the respective Plan's net OPEB liability would be if it were calculated using trend rates that are one-percentage-point lower or one-percentage-point higher than the current healthcare cost trend rates (in thousands):

June 30, 2019	Proportional Share	1% Decrease	Healthcare Cost Trend Rate	1% Increase
Utility's proportionate share of the NOL- ARHCT	0.18439%	$ (1,497,119)	$ 273,600	$ 2,434,544
Utility's proportionate share of the NOL- RMP	0.24273%	(17,860)	58,071	162,014
Utility's proportionate share of the NOA- ODD	0.32582%	N/A	78,996	N/A
June 30, 2018				
Utility's proportionate share of the NOL- ARHCT	0.22860%	$ 45,543	$ 2,346,143	$ 5,117,441
Utility's proportionate share of the NOL- RMP	0.26596%	(28,774)	33,844	117,646
Utility's proportionate share of the NOA- ODD	0.26596%	N/A	(51,655)	N/A

OPEB Plan Fiduciary Net Position

Detailed information about the OPEB plan's fiduciary net position is available in the separately issued PERS financial report.

(e) State of Alaska Public Employees' Retirement System Defined Contribution OPEB Plans

General Information About the Plans

Defined Contribution Pension Plan participants (PERS Tier IV) participate in the ODD Plan, and the RMP. Information on these plans is included in the comprehensive annual financial report for the PERS Plans noted above. These plans provide for death, disability, and postemployment healthcare benefits.

Employer Contribution Rates

Employees do not contribute to the Defined Contribution OPEB plans. Employer contribution rates for the years ended December 31, 2019 and 2018 were as follows:

2019

	Tier IV	
	1/1 - 6/30	7/1 - 12/31
Employer Contribution		
Health Reimbursement Arrangement	3.00%	3.00%
Retiree Medical Plan	0.94%	1.32%
Death & Disability Benefit	0.26%	0.26%
Total Employer Contribution	4.20%	4.58%

Retirement and OPEB Plans, continued

State of Alaska Public Employees' Retirement System Defined Contribution OPEB Plans, continued

2018

	Tier IV	
	1/1 - 6/30	7/1 - 12/31
Employer Contribution		
Health Reimbursement Arrangement	3.00%	3.00%
Retiree Medical Plan	1.03%	0.94%
Death & Disability Benefit	0.16%	0.26%
Total Employer Contribution	4.19%	4.20%

Healthcare Reimbursement Arrangement
In addition, PERS defined contribution members also participate in the Health Reimbursement Arrangement. AS 39.30.370 establishes the employer contribution amount as "three percent of the employer's average annual employee compensation of *all employees of all employers* in the plan".

Prior to July 1, 2018 a flat rate of approximately $2,084 per year for full time employees and $1.34 per part time hour worked was paid. For pay periods ending after July 1, 2018, a flat rate of approximately $2,103 per year for full time employees and $1.35 per part time hour worked were paid. For pay periods ending after July 1, 2019, a flat rate of approximately $2,122 per year for full time employees and $1.36 per part time hour worked were paid.

Annual Postemployment Healthcare Cost
The Utility contributed $128,167 and $122,740 in Defined Contribution OPEB costs for the years ended December 31, 2019 and 2018, respectively.

(8) Commitments and Contingencies

The Utility, in the normal course of its activities, is involved in various claims and pending litigation. In the opinion of management and the Municipality's legal department, the disposition of these matters is not expected to have a material adverse effect on the Utility's financial statements.

(a) Environmental

Fuel/Polychlorinated Biphenyl (PCB) Contaminated Sites at Hank Nikkels Power Plant 1 and Operations/Dispatch Center

During the 1964 earthquake, approximately 250,000-400,000 gallons of diesel fuel spilled on the ground. Based on numerous environmental investigations, the spill impacted soil and groundwater at the Hank Nikkels Power Plant 1 and properties west/northwest of the plant. During the 2006-2007 subsurface investigation, in addition to diesel contamination known from the 1964 spill, PCBs were detected in the soil. All soil disturbing activities at the site are governed by the Risk-Based Disposal Plan (RBDP) administered by the Alaska Department of Environmental Conservation (ADEC) and the Environmental Protection Agency (EPA).

Commitments and Contingencies, continued

Environmental, continued

In May 2017, the Utility conducted PCB cleanup activities at the plant and paved the surface of the cleanup area in accordance with the 2008 RBDP approved by EPA and ADEC. All cleanup activities were considered to be performed during 2018.

In 2009, PCB contaminated soil was discovered near the Operations/Dispatch building during excavation to install water lines for a fire suppression system. In 2010 and 2015 additional site investigations were conducted to determine a horizontal and vertical extent of PCB contamination. Following the soil investigations the Utility performed monitoring of groundwater at the site and in the vicinity during 2015 and 2016. Analytical results indicated no off-site migration of PCBs. The Utility is waiting on EPA's review of the site data and further decisions. The cost associated with any further actions cannot be determined at this time.

Petroleum Contaminated Sites and Spill Cleanup

In 2018, based on an ADEC request, the Utility conducted a vapor intrusion assessment associated with the old petroleum contamination in the subsurface near and under the Transformer Shop. The assessment concluded that there were no petroleum vapors entering the Transformer Shop from the subsurface. In response to the assessment, ADEC requested to continue biennial groundwater monitoring at this site and include additional volatile organic compounds into the monitoring program. The Utility's environmental consultant will prepare a work plan and conduct groundwater sampling during the summer of 2020. The Utility does not anticipate any material environmental liability associated with this contaminated site.

Compliance with Air Quality Permits

The Utility owns three turbines that are subject to hourly and annual emissions limits emission controls for criteria pollutants, NOx and CO. In addition to maintaining continuous emission monitoring systems (CEMS) on each turbine, the two newly installed turbines requires operation with post-combustion emission controls. EPA regulations require annual third party emissions testing to assure accuracy of the CEMS. Newly installed turbines have significant emissions reductions compared to the existing turbines, however maintaining emissions control equipment and performing all testing required by the EPA will remain a significant part of the overall environmental compliance cost. The Utility will oversee environmental compliance and contract qualified third-party experts to perform necessary services. Environmental permitting and compliance will continue to require a consultant's expertise. The cost of compliance cannot be determined at this time.

(b) Petroleum Production Tax (PPT)

For tax year 2019, the Utility estimated that its PPT liability under AS 43.55.011(e) for non-royalty gas is zero and its liability under AS 43.44.011(i) for private royalty gas is $3,429. Monthly installment payments from February 2019 through January 2020 totaled $86,268.

For tax year 2018, the Utility estimated that its PPT liability under AS 43.55.011(e) for non-royalty gas is zero and its liability under AS 43.44.011(i) for private royalty gas is $4,370. Monthly installment payments from February 2018 through January 2019 totaled $104,554.

Commitments and Contingencies , continued

(c) Petroleum Production Credits

Pursuant to AS 43.55.023, the Utility applies for Alaska oil and gas tax credits from the State of Alaska Department of Revenue (DOR). The Utility records the receipt of cash from tax credits as a restricted investment and as a deferred inflow of resources for the benefit of customers. During 2019 and 2018, the Utility did not apply for tax credits. The amounts received by the Utility are subject to final resolution of DOR audits, and are not recorded until cash is received.

(d) Contractual Commitments

The Utility has purchase commitments to contractors and suppliers at December 31, 2019 of approximately $10 million. Those commitments are for contracts, materials and services related to construction and maintenance of the Utility's generation and distribution system assets, regulatory filings contracted billing services, and janitorial and security services. Construction of plant assets is financed with contributions in aid of construction and Utility equity, and operating commitments are financed with Utility revenues.

(9) Regulatory Matters

(a) Beluga River Unit Underlift Settlements

Until April 2016, the Utility owned a one-third interest in annual production of the BRU. Its field partners at that time - CPAI and Hilcorp Alaska, LLC - each also owned a one-third interest in BRU production. Every BRU owner has a right to take a portion of annually produced gas proportionate to its interest.

In 2005, the Utility underlifted (i.e. took less than its interest in BRU's annual output) and accepted a monetary settlement from its field partners. These funds were deposited in a Future Natural Gas Purchases Account (FGP), and the Utility recorded deferred inflows of resources for future natural gas purchases. The balances of the Future Natural Gas Purchases Account, as of December 31, 2019 and 2018 were $18,230,036 and $17,934,651, respectively.

In 2015, the Utility petitioned the RCA for authorization to apply 2014 underlift settlement proceeds to reduce its GTP in effect from July 1, 2016 through June 30, 2017. The RCA approved the Utility's unopposed proposal in Order U-15-116(2), dated March 10, 2016.

In April 2016, the Utility purchased 70% of CPAI's one-third interest in the BRU. The RCA approved the Utility's request in Order U-16-012(14), dated April 21, 2016, to utilize a closing underlift settlement from CPAI of $13,177,726 towards financing this acquisition. See Note 9(f).

Regulatory Matters, continued

(b) *Regulatory Debits/Credits*

The Utility files a COPA rate quarterly with the RCA to recover cost of power expenses not recovered in base rates. The COPA calculation is based on the projected cost of fuel and purchased power for the applicable quarter, the projected kilowatt hour sales for the applicable quarter, and the over- or under- recovered balance in the cost of power clearing account. The Utility records in the cost of power clearing account an asset with an offsetting credit to a contra revenue account for under recovered costs or a liability and an offsetting debit to a contra revenue account for over recovered costs. The Utility over-recovered as of December 31, 2019 in the amount of $1,562,679 and under-recovered as of December 31, 2018 in the amount of $1,904,402.

Prior to October 24, 2017, the Utility annually set the GTP with its third quarter COPA filings. (See Note 9 (g) for the new schedule in filing the GTP.) Through the GTP, the Utility recovers the Gas Fund's annual revenue requirement associated with the Utility's ownership interest in the BRU and any over or under recovery from the prior year. The Utility records in the cost of Gas Transfer Price Clearing Account an asset and a credit to an expense account for under-recovered costs or a liability and debit to an expense account for over-recovered costs. The Utility under-recovered as of December 31, 2019 and 2018 in the amount of $4,793 and $1,647,342, respectively.

c) *Deferred Regulatory Liability for Gas Sales*

Revenue from third party sales of natural gas produced at the BRU is excluded from the GTP calculation. These funds, net of royalties and the ARO surcharge, are recorded in the Utility's Future BRU Construction or Natural Gas Purchases account, reported on the statement of net position as deferred inflows of resources, and referred to for regulatory purposes as the Deferred Regulatory Liability from Gas Sales (DRLGS) Account. These funds are to be used for future BRU construction or natural gas purchases. The balances of the DRLGS account, as of December 31, 2019 and 2018, were $10,106,438 and $8,077,741, respectively.

(d) *Asset Retirement Obligation Sinking Fund*

ARO expenses associated with future abandonment of the BRU are funded through a surcharge to the Utility's GTP. This surcharge is deposited into a sinking fund investment account. As of December 31, 2019 and 2018, the sinking fund account balances were $16,342,806 and $13,915,853, respectively.

On page 24 of its revised petition in Docket U-14-009, dated January 29, 2014, the Utility stated that it would "each year, as part of [its] third quarter COPA filing, update the projected interest earnings rate for the ARO surcharge calculation." In accordance with that requirement, in TA375-121, the Utility updated its future interest earnings estimate to 4.7%. This estimate is based on the targeted earnings rates established by the ARO Board Investment Guidelines of CPI-U plus 200 basis points. CPI-U for Anchorage was at 2.7% in 2019. The actual average earnings over the most recent 12-month period was 5.87% and the actual average earnings over the most recent 6-month period was 7.66%. The Utility will continue to review the projected interest earnings as part of its semiannual ARO surcharge filing.

Regulatory Matters, continued

In accordance with U-14-009(2) the Utility is required to update its field abandonment cost estimate for the ARO surcharge every 5 years. With the filing of TA375-121, the Utility submitted its updated cost estimate. The updated cost estimate for the field was $56.9 million, comprised of $28.5 million for above ground assets and $28.4 million for below ground assets. The updated estimate is higher than the prior field estimate of $33.5 million produced in the 2013 study.

Significant factors contributing to the increase include new facilities and increased regulatory requirements for remediation. The above ground cost increased approximately $5.6 million for the removal of a site compressor and water gathering system. Also included in the updated study are the cost estimates to remediate contaminated sites in the field. The below ground estimate for plugging and abandonment of the 25 existing wells increased approximately $18 million due to new regulatory requirements that require additional cement barriers to complete well abandonment downhole. Labor, material and equipment costs to construct the cement barriers are the primary factors leading to the increase in the below ground well abandonment cost.

Also in accordance with U-14-009(2) the Utility is required to update its BRU production projections for the ARO surcharge every 3 years. With the filing of TA375-121, the Utility submitted its updated production projections. Based on the updated 2019 report completed by Ryder Scott, the Utility's share of the remaining gas reserves, net of fuel gas, is 82 billion cubic feet. The end of the life of the field is estimated to occur in 2038.

(e) Revenue Requirement Studies

On December 30, 2016 the Utility filed a petition with the RCA, based on a 2015 test year revenue requirement study, for interim and permanent across-the-board rate increases in energy and demand charges in order to recover costs associated with its construction of Plant 2A. The Utility requested a 29.49% interim and refundable rate increase, based on RCA approval of the Utility's proposed rate stabilization plan (RSP). On February 13, 2017 the RCA granted the Utility an interim and refundable rate increase of 37.30%, denied approval of the Utility's proposed RSP, and suspended the Utility's request into Docket U-17-008 for further investigation. A public hearing was held on this matter that began on November 16, 2017, and continued through December 21, 2017. The RCA issued a final order on March 23, 2018 [U-17-008(13)] approving a 37.32% increase in the revenue requirement.

In two separate submittals at the Superior Court, Providence Health and Services (PHS) appealed the decision by the RCA on (1) Order 10 - refund order and (2) Order 13 - final order. The Superior Court rendered an Order on Order 13 (final order) on May 20, 2019 - reversing and remanding the RCA Order 13 for further proceedings consistent with the Superior Court's Order and the reasons that supported the Order. The RCA was ordered to "make findings and conclusions on whether the Utility met its burden to demonstrate that the decision to construct Plant 2A was prudent, reopening the evidentiary record if necessary." The RCA also has to provide the process by which it arrived at the final ROE of 10.7%.

Regulatory Matters, continued

On May 28, 2020, as part of the acquisition dockets (U-19-020/U-19-021/U-18-102), the RCA accepted the Amended Remand Stipulation, reaffirmed the Utility's current rates as permanent, and closed the Utility's rate case docket (U-17-008). This stipulation was signed by the Utility, Providence Health and Services, the Federal Executive Agency, and Attorney General for the State of Alaska. It resolved the remanded issues by agreeing to the permanent rates as set in the rate case. (See Note 9 (i))

(f) Acquisition of CPAI's Interest in the BRU

In Order U-16-012(14), dated April 21, 2016, the RCA granted a joint petition filed by the Utility and CEA requesting approval of a purchase and sale agreement for the acquisition of CPAI's one-third interest in the BRU. The total purchase price was $152 million, with the Utility acquiring 70% of that interest for $106.4 million and CEA the remaining 30% for $45.6 million. The Utility funded its share of the acquisition with DRLGS and Future Natural Gas Purchases Account funds, cumulative and underlift proceeds owed to it by CPAI. With this purchase the Utility has a 56.67% interest in the BRU.

(g) BRU Ratemaking and Accounting Treatment - Aggregate BRU Interest

On June 20, 2016, the Utility filed for approval from the RCA for some changes in the ratemaking and accounting treatment applicable to the Aggregate BRU Interest. Ruling under Docket U-16-060(12), the RCA granted in part the request on October 24, 2017. The use of rate base/rate of return (RB/ROR) methodology to calculate the gas fund revenue requirement beginning in 2019 was approved. The use of a system-wide weighted average cost of capital (WACC) for calculating the gas fund revenue requirement was approved. The RCA also approved the inclusion of depletion expense using the units of production methodology for calculating the gas fund revenue requirement.

Because the GTP is one component of the COPA and Small Facility Power Purchase Rate (SFPPR), several 2017 tariff advice filings were suspended and were filed under Docket U-16-073. On October 24, 2017, these were approved and made permanent.

In its own motion the RCA opened Docket U-18-102 to specifically investigate the Utility's BRU gas management procedures, including use of its share of BRU gas for economy energy sales and the appropriate pricing of BRU gas that is used for economy energy sales. The RCA also opened Docket U-18-102 to investigate the adequacy of the ARO surcharge. An order in Docket U-18-102 revising the ARO surcharge used in the Utility's GTP calculation will directly affect both the COPA and the SFPPR proposed in COPA filings by the Utility. An order in Docket U-18-102 affecting the pricing of economy energy sales by the Utility would also affect the COPA proposed in COPA filings.

Regulatory Matters, continued

One COPA filing in 2019, TA373-121, was directly affected by the matters under investigation in Docket U-18-102. Accordingly, the RCA suspended TA373-121 for further investigation. The rates shown on the tariff sheets are approved on an interim and refundable basis effective October 1, 2019. In addition, the gas transfer price of $2.15705 per thousand cubic feet was approved on an interim and refundable basis, effective October 1, 2019.

On May 28, 2020, as part of the acquisition Dockets (U-19-020/U-19-021), the RCA ruled the use of market value proxy mechanism in pricing economy energy sales using the Utility's BRU interest gas. The methodology is set out in Section 2.05 of the Restated BRU Agreement, which is one of the agreement documents of the acquisition dockets. This requirement was effective May 28, 2020.

The Utility's tax credit appeal at the Office of Administrative Hearings (OAH), 17-0379-TAX, is still ongoing. The Department of Revenue and the Utility are currently working on analyzing discovery requests and responses from both sides.

(h) Bradley Lake Transmission

Homer Electric Association, Inc. (HEA) filed a rate case on November 15, 2013 requesting RCA's approval of postage stamp rates for Bradley Lake energy wheeled over HEA's system. The Utility intervened, arguing in part that the Bradley Lake Agreements govern the obligations of Bradley Lake participants and that the RCA was statutorily precluded, under AS 42.05.431(c), from reviewing these wheeling rates. On June 30, 2014, the RCA issued an order establishing interim rates for wheeling Bradley Lake energy from the Soldotna to Quartz Creek Substations. The parties appealed to the state superior court, which ruled May 27, 2015 that the RCA lacks jurisdiction over Bradley Lake wheeling rates. All parties appealed this decision to the Alaska Supreme Court. The parties engaged in lengthy mediation, and filed reply briefs with the Alaska Supreme Court. Oral arguments before the Alaska Supreme Court were heard May 31, 2018. On February 22, 2019, the Supreme Court issued an opinion affirming the Superior Court's decision reversing the RCA's order.

Regulatory Matters, continued

(i) Acquisition of the Utility by CEA

On April 1, 2019, CEA filed a petition at the RCA requesting necessary approvals for acquiring the Utility from the Municipality and requesting an amendment of Certificate of Public Convenience and Necessity (CPCN) No. 8 to reflect the acquired service territory. This filing was assigned Docket U-19-020. CEA has agreed to acquire most of the assets of the Utility from the Municipality. CEA and the Municipality have agreed to a transaction in which CEA will purchase most of the Utility's assets and the generation output of the Utility's share of the Eklutna Hydroelectric Project for a term of 35 years.

On April 5, 2019, the Municipality applied for approval from the RCA to amend its CPCN No. 121 to consist solely of wholesale bulk power sales at the Eklutna generation plant. The Municipality also applied to terminate the restriction on payment of dividends to the Municipality initially imposed by Order No. U-13-184(22). This filing was assigned Docket U-19-021.

On May 8, 2019, the RCA ordered the consolidation of U-19-020 and U-19-021. Hearings occurred from August 27, 2019 to November 8, 2019. Two stipulations agreed upon by most parties in the dockets were presented to the RCA - Acquisition stipulation and Remand stipulation. The remand stipulation revolves around the appeal by PHS on the prudency of the Utility's Plant 2A (see Note 9(e)). On February 21, 2020, the RCA closed Docket U-17-008, which addressed the remand stipulation. The RCA was then left with reviewing the acquisition stipulation.

On May 28, 2020, the RCA issued a ruling addressing the acquisition Dockets, U-19-020(39) and U-19-021(39), and part of the BRU Management Practices, U-18-102(44). The RCA did not approve the sale as proposed, but did approve the sale if parties agree to modify the transaction as required in the final order. The approval of the transaction is subject to the following conditions: (1)Unified COPA surcharges and rejection of the BRU Fuel Agreement cost and benefit allocations as unreasonably discriminatory; (2)Unified base rates to be filed in Chugach's first rate case. The PILT Agreement's proposed recovery of payments only from former ratepayers of the Utility through 2033 must be rejected; (3) CEA and MEA forming a tight power dispatch pool.

If the transaction closes under these dockets, the RCA will terminate the dividend restriction imposed on the Utility by Order U-13-184(22). This will allow disbursement of the Utility's assets as contemplated by the transaction.

At this time, CEA, the Municipality, and all the other parties in the docket have yet to provide their response whether they accept the conditions as ruled by the RCA.

Regulatory Matters, continued

(j) Petition to Adjust Depreciation Rates

On December 31, 2018, the Utility filed a petition at the RCA for approval of revised depreciation rates (Docket U-18-121). The study was based on the Utility's electric plant balances and continuing property records as of December 31, 2017. The Utility requested that the depreciation rates be approved for implementation as of the next accounting month following final approval by the RCA. On June 18, 2019, Order 2 was issued. The RCA denied the petition citing the results of the recently concluded rate case in Docket U-17-008 and that they did not find the $2.5 million revenue requirement reduction recommended in the 2018 Depreciation Study to be so materially substantial that the RCA should require the Utility to incur the cost of filing a new rate case. The RCA further explains that the lack of synchronization between the requested depreciation rates and the current rates charged for electric public utility service. The denial will allow the depreciation rates previously found to be adequate but not excessive to remain in effect, and will result in depreciation expense collected from customers matching depreciation being recorded. The Utility was ordered to file another depreciation study in 2024, or when it files its next rate case.

(k) Senate Bill 241

A bill introduced in the Senate of the Alaska Legislature was signed by Governor Dunleavy on April 10, 2020. This Act extended the Governor's declaration of public health disaster emergency mandate in response to the novel coronavirus (COVID-19) that was issued on March 10, 2020. It provides for a financial plan and made temporary changes to state law in response to the COVID-19 outbreak in response to several areas. One of these areas is on regulatory assets for unpaid utility bills and extraordinary expenses. A utility certified under AS 42.05 may record regulatory assets, to be recovered through future rates, for uncollectible residential utility bills and extraordinary expenses that result from the novel coronavirus disease public health disaster declared by the Governor. The determination as to whether an extraordinary expense resulted from the COVID-19 public health disaster emergency, and the amortization periods for the regulatory assets are subject to approval by the RCA before recovery occurs through future rates. In this section, an "uncollectable residential utility bill" does not include a debt paid under a deferred payment agreement.

The Utility has suspended utility shut offs as of March 17, 2020. Customers are encouraged to pay on time, as they are able. Each unpaid utility bill will continue to accrue. Customers who are not able to pay are encouraged to contact Customer Service to work out a payment plan. Under SB241, the Utility is prohibited from disconnecting service or imposing late fees for the duration of the emergency. In order to avoid disconnection for non-payment and late fees, a residential customer must provide a statement of financial hardship, and negotiate a deferred payment agreement with the Utility. This was offered by the Utility to its customers.

Regulatory Matters, continued

On May 1, 2020, the RCA issued Order U-20-015, Order Permitting Deviation from Tariff Under AS 42.05.711(d). This order addresses deviations by utilities from their approved tariffs as they avoid disconnections to their customers. Instead of formally requesting approval to deviate, the RCA requires a certificated public utility to promptly make informational filing in U-20-015 describing how it is deviating from its tariff. The Utility's tariff language pertaining to disconnections is not violated, therefore no information filing is needed for the Utility.

(10) Risk Management and Self Insurance

The Municipality is exposed to various risks of loss related to torts; theft of, damage to and destruction of assets; errors and omissions; illness of and injuries to employees; unemployment; and natural disasters. The Municipality utilizes three risk management funds to account for and finance its uninsured risks of loss.

The Municipality provides coverage up to the maximum of $3,000,000 per occurrence for automobile and general liability claims and for each workers' compensation claim. No settled claim exceeded this commercial coverage in 2019, 2018 or 2017.

Unemployment compensation expense is based on actual claims paid by the State of Alaska and reimbursed by the Municipality.

The Utility participates in the Municipality's risk management program and makes payments to the Municipality through inter-governmental charges based on actuarial estimates of the amounts needed to pay prior and current year claims (See Note 1(o).) The Utility does not include any portion of the Municipality's claims payable among its liabilities on the Statements of Net Position.

(11) Other GAAP Disclosures

The Municipality has entered into an agreement to sell certain assets and discharge certain liabilities of the Utility to CEA as outlined in Note 13. CEA is a non-governmental entity and, as such, follows the Financial Accounting Standards Board (FASB) accounting framework to prepare its financial statements. The Utility's financial statements are prepared according to the GASB framework, and therefore the accounting for certain items could differ from the accounting treatment by CEA. The table beginning on the following page presents relevant authoritative accounting pronouncements under the respective GASB and FASB frameworks to provide clarification to the users of these statements.

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Net Pension Liabilities	GASBS 68 Paragraph 59 - A liability should be recognized for the employer's proportionate share of the collective net pension liability, measured as of a date (measurement date) no earlier than the end of the employer's prior fiscal year, consistently applied from period to period. The employer's proportionate share of the collective net pension liability should be measured by: a. Determining the employer's proportion—a measure of the proportionate relationship of (1) the employer (and, to the extent associated with the employer, nonemployer contributing entities, if any, that provide support for the employer but that are not in a special funding situation) to (2) all employers and all nonemployer contributing entities. b. Multiplying the collective net pension liability by the employer's proportion calculated in (a).	FASB ASC Topic 715-30-25 Paragraph 1 - If the projected benefit obligation exceeds the fair value of plan assets, the employer shall recognize in its statement of financial position a liability that equals the unfunded projected benefit obligation. If the fair value of plan assets exceeds the projected benefit obligation, the employer shall recognize in its statement of financial position an asset that equals the overfunded projected benefit obligation.

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to Pensions	GASBS 68 Paragraph 71 - Changes in the collective net pension liability should be included in collective pension expense in the current measurement period except as indicated below: a. Each of the following should be included in collective pension expense, beginning in the current measurement period, using a systematic and rational method over a closed period equal to the average of the expected remaining service lives of all employees that are provided with pensions through the pension plan (active employees and inactive employees) determined as of the beginning of the measurement period: (1) Differences between expected and actual experience with regard to economic and demographic factors (differences between expected and actual experience) in the measurement of the total pension liability (2) Changes of assumptions about future economic or demographic factors or of other inputs (changes of assumptions or other inputs). The portion of (1) and (2) not included in collective pension expense should be included in collective deferred outflows of resources or deferred inflows of resources related to pensions. b. The difference between projected and actual earnings on pension plan investments should be included in collective pension expense using a systematic and rational method over a closed five-year period,	ASC Topic 715-30-35 Paragraph 18 - As established in the definition of the term, a gain or loss results from a change in the value of either the projected benefit obligation or the plan assets resulting from experience different from that assumed or from a change in an actuarial assumption. Paragraph 19 - Because gains and losses may reflect refinements in estimates as well as real changes in economic values and because some gains in one period may be offset by losses in another or vice versa, this Subtopic does not require recognition of gains and losses as components of net pension cost of the period in which they arise. Paragraph 22 - Asset gains and losses are differences between the actual return on plan assets during a period and the expected return on plan assets for that period. Asset gains and losses include both changes reflected in the market-related value of plan assets and changes not yet reflected in the market-related value (that is, the difference between the fair value of assets and the market-related value). Gains or losses on transferable securities issued by the employer and included in plan assets are also included in asset gains and losses. Paragraph 23 - In other words, the expected return on plan assets generally will be different from the actual return on plan assets for the year. This Subtopic provides for recognition of that difference (a net gain or loss) in other comprehensive income in the period it arises. The amount recognized in other

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to Pensions, continued	beginning in the current measurement period. The amount not included in collective pension expense should be included in collective deferred outflows of resources or deferred inflows of resources related to pensions. Collective deferred outflows of resources and deferred inflows of resources arising from differences between projected and actual pension plan investment earnings in different measurement periods should be aggregated and included as a net collective deferred outflow of resources related to pensions or a net collective deferred inflow of resources related to pensions.	comprehensive income is also a component of net periodic pension cost for the current period. Thus, the amount recognized in other comprehensive income and the actual return on plan assets, when aggregated, equal the expected return on plan assets. The amount recognized in accumulated other comprehensive income affects future net periodic pension cost through subsequent amortization, if any, of the net gain or loss.
Net Other Post Employment Benefits Liabilities	GASBS 75 Paragraph 109 - A liability should be recognized for the employer's proportionate share of the collective net OPEB liability determined in conformity with paragraphs 59-61. (Paragraph 59 - The employer's proportionate share of the collective net OPEB liability should be measured by: (a) Determining the employer's proportion - a measure of the proportionate relationship of (1) the employer.. to (2) all employers and all nonemployer contributing entities... (b) Multiplying the collective net OPEB liability (determined in conformity with paragraphs 70-85) by employer's proportion calculated in (a). Paragraph 70 - The collective net OPEB liability should be measured as the total OPEB liability net of the	FASB ASC Topic 715-60-25 Paragraph 1 - An employer that sponsors one or more single-employer defined benefit postretirement plans other than pensions shall recognize in its statement of financial position the funded statuses of those plans. The employer shall aggregate the statuses of all overfunded plans and recognize that amount as an asset in its statement of financial position. It also shall aggregate the statuses of all underfunded plans and recognize that amount as a liability in its statement of financial position. Paragraph 2 - As indicated in paragraphs 715-60-35-125 through 35-126 remeasurement of both plan assets and the accumulated postretirement benefit obligation may be necessary. Upon remeasurement, a business entity shall adjust its statement of financial position in a

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Net Other Post Employment Benefits Liabilities, continued	OPEB plan's fiduciary net position. Paragraph 71 - The total OPEB liability should be determined by (a) an actuarial valuation as of the measurement date or (b) the use of update procedures to roll forward to the measurement date amounts from an actuarial valuation as of a date no more than 30 months and 1 day earlier than the employer's most recent fiscal year end.. If update procedures are used and significant changes occur between the actuarial valuation date and the measurement date, professional judgment should be used to determine the extent of procedures needed to roll forward the measurement from the actuarial valuation to the measurement date, and consideration should be given to whether a new actuarial valuation is needed. For purposes of this determination, the effects of changes in the discount rate resulting from changes in the OPEB plan's fiduciary net position or from changes in the municipal bond rate, if applicable, should be among the factors evaluated. For accounting and financial reporting purposes, an actuarial valuation of the total OPEB liability should be performed at least biennially. More frequent actuarial valuations are encouraged.	subsequent interim period to reflect the overfunded or underfunded status of the plan consistent with that measurement date.

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to OPEB	GASBS 75 Paragraph 86 - Changes in the collective net OPEB liability should be included in collective OPEB expense in the current measurement period except as indicated below: (a) If the alternative measurement method is not used to measure the total OPEB liability, each of the following should be recognized in collective OPEB expense, beginning in the current measurement period, using a systematic and rational method over a closed period equal to the average of the expected remaining service lives of all employees that are provided with OPEB through the OPEB plan determined as of the beginning of the measurement period: (1) Differences between expected and actual experience with regard to economic or demographic factors (differences between expected and actual experience) in the measurement of the total OPEB liability. (2) Changes of assumptions about future economic or demographic factors or of other inputs (changes of assumptions or other inputs). The portion of (1) and (2) not recognized in collective OPEB expense should be reported as collective deferred outflows of resources or deferred inflows of resources related to OPEB. (b) The difference between projected and actual earnings on OPEB plan investments should be included in collective OPEB expense using a	ASC Topic 715-60-35 Paragraph 7 - As with other forms of deferred compensation, the cost of providing postretirement benefits shall be attributed to the periods of employee service rendered in exchange for those future benefits pursuant to the terms of the plan. That cost notionally represents the change in the unfunded accumulated postretirement benefit obligation for the period, ignoring employer contributions to the plan, plan settlements, and payments made by the employer directly to retirees. However, changes in that unfunded obligation that arise from experience gains and losses and the effects of changes in assumptions may be recognized as a component of net periodic postretirement benefit cost on a delayed basis. Paragraph 8 - Thus any change in the accumulated postretirement benefit obligation or the plan assets (other than contributions and benefit payments) either is initially recognized in other comprehensive income or is included in net periodic postretirement benefit cost. Paragraph 24 - Because gains and losses may reflect refinements in estimates as well as real changes in economic values and because some gains in one period may be offset by losses in another or vice versa, this Subtopic does not require recognition of gains and losses as components of net postretirement benefit cost of the period in which they arise.

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to OPEB, continued	systematic and rational method over a closed five-year period, beginning in the current measurement period. The amount not included in collective OPEB expense should be included in collective deferred outflows of resources or deferred inflows of resources related to OPEB. Collective deferred outflows of resources and deferred inflows of resources arising from differences between projected and actual OPEB plan investment earnings in different measurement periods should be aggregated and included as a net collective deferred outflow of resources related to OPEB or a net collective deferred inflow of resources related to OPEB. (c) Contributions to the OPEB plan from employers or nonemployer contributing entities should not be included in collective OPEB expenses.	Paragraph 25 - Gains and losses that are not recognized immediately as a component of net periodic postretirement benefit cost shall be recognized as increases or decreases in other comprehensive income as they arise. Paragraph 27 - Plan asset gains and losses are differences between the actual return on plan assets during a period and the expected return on plan assets for that period. Asset gains and losses include both of the following: a. Changes reflected in the market-related value of plan assets b. Changes not yet reflected in the market-related value of plan assets (that is, the difference between the fair value and the market-related value of plan assets).

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Contributions in Aid of Construction	GASBCS4 Paragraph 34. A deferred inflow of resources is an acquisition of net position by the government that is applicable to a future reporting period.	FASB ASC 210-10-S99 Paragraph 13(b) Tangible and intangible utility plant of a public utility company shall be segregated so as to show separately the original cost, plant acquisition adjustments, and plant adjustments, as required by the system of accounts prescribed by the applicable regulatory authorities.
Restricted Assets	GASBS 34 Paragraph 99 - Restricted assets should be reported when restrictions on asset use change the nature or normal understanding of the availability of the asset. For example, cash and investments normally are classified as current assets, and a normal understanding of these assets presumes that restrictions do not limit the government's ability to use the resources to pay current liabilities. But cash and investments held in a separate account that can be used to pay debt principal and interest only (as required by the debt covenant) and that cannot be used to pay other current liabilities should be reported as restricted assets. Because restricted assets may include temporarily invested debt proceeds or other resources that are not generated through operations (such as customer deposits), the amount reported as restricted assets will not necessarily equal restricted net position.	FASB ASC 210-10-S99-1 Paragraph 1 - Cash and cash items. Separate disclosure shall be made of the cash and cash items which are restricted as to withdrawal or usage. The provisions of any restrictions shall be described in a note to the financial statements. Restrictions may include legally restricted deposits held as compensating balances against short-term borrowing arrangements, contracts entered into with others, or company statements of intention with regard to particular deposits.

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Transfers to Other Funds	GASBS 34 Paragraph 112b - Nonreciprocal interfund activity is the internal counterpart to nonexchange transactions. It includes: Interfund transfers—flows of assets (such as cash or goods) without equivalent flows of assets in return and without a requirement for repayment. This category includes payments in lieu of taxes that are not payments for, and are not reasonably equivalent in value to, services provided.	Not addressed in FASB reporting framework
Non-Operating Revenues and Expenses	GASBS 34 Paragraph 102 - Governments should establish a policy that defines operating revenues and expenses that is appropriate to the nature of the activity being reported, disclose it in the summary of significant accounting policies, and use it consistently from period to period. A consideration for defining a proprietary fund's operating revenues and expenses is how individual transactions would be categorized for purposes of preparing a statement of cash flows. Transactions for which cash flows are reported as capital and related financing activities, noncapital financing activities, or investing activities normally would not be reported as components of operating income.	FASB ASC Topic 360-10-45-5 - A gain or loss recognized on the sale of a long-lived asset that is not a discontinued operation shall be included in income from continuing operations before income taxes.

Other GAAP Disclosures, continued

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Asset Retirement Obligations	The Utility uses the Guidance from FASB ASC Topic 980 (Formerly FASBS 143) to record asset retirement obligations. The implementation date for GASBS 83 *Certain Asset Retirement Obligations* has been postponed until fiscal year 2020.	FASB ASC Topic 980-410-25-2 - Many rate-regulated entities currently provide for costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of subtopic 410-20; others result from costs that are not within the scope of the subtopic. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs for financial reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. If the requirements of this topic are met, a regulated entity shall also recognize a regulatory asset or liability for differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting pursuant to that Subtopic and rate-making purposes.

(12) Other Matters

(a) Eklutna Hydroelectric Project

On October 2, 1997, the ownership of the Eklutna Hydroelectric Project was formally transferred from the Alaska Power Administration, a unit of the United States Department of Energy, to the three participating utilities: the Utility, CEA and Matanuska Electric Association (MEA). The project is jointly owned and operated by the participating utilities and each contributes their proportionate share for operation, maintenance, and capital improvement costs, as well as maintenance of the transmission line between Anchorage and the hydroelectric plant. The Utility has a 53.33% ownership interest in the project and recorded operating and maintenance costs of $542,438 and $409,562 in 2019 and 2018, respectively. Capital costs for 2019 and 2018 were $965,640 and $373,142, respectively. In addition, the Utility paid transmission costs for hydroelectric power of $42,688 and $26,132 in 2019 and 2018, respectively. The operations and maintenance costs are part of production expenses in the Statements of Revenue, Expenses and Changes in Net Position and the capital costs are part of plant assets reported in the Statements of Net Position.

(b) Bradley Lake Hydroelectric Project

The Utility agreed to acquire a portion of the output of the Bradley Lake Hydroelectric Project (Project) pursuant to a Power Sales Agreement (Agreement). The Agreement specifies the Utility acquire 25.9% of the output of the Project.

The Project went on line September 1, 1991. The Utility made payments to the Alaska Energy Authority (AEA) of $4,997,622 in 2019 for its portion of costs, and received 66,345 megawatt hours of power from the Project. In 2018 the Utility paid $5,028,039 and received 102,307 megawatt hours. The Utility received a budget surplus refund in the amount of $226,448 for 2019. During the late summer and fall of 2019, the Swan Lake fire resulted in the transmission line from Bradley Lake to be de-energized for several months. The Utility as well as its other partners in the Project were unable to receive delivery of power from the Project until the fire was extinguished and the line was assessed and repaired. The line was fully operational by the end of November 2019. The Utility's estimated cost of power from the Project for 2020 is $2,536,188.

AEA issued the Power Revenue Bonds, First and Second Series in September 1989 and August 1990, respectively, for the long term financing of the construction costs of the Project. On July 1, 2010, AEA issued $28,800,000 principal amount of Power Revenue Bonds, Sixth Series. The Sixth Series Bonds were issued for the purpose of refunding the Power Revenue Bonds, Fifth Series Bonds to take advantage of lower interest rates. The total amount of debt outstanding as of December 31, 2019 is $22,445,000. The pro rata share of the debt service costs of the Project for which the Utility is responsible, given its 25.9% share of the Project, is $6,276,098. In the event of payment defaults by other power purchasers, the Utility's share could be increased by up to 25%, which would then cause the Utility's pro rata share of Project debt service to be a total of $7,845,122. The Utility does not now know of or anticipate any such defaults.

Other Matters, continued

(c) Southcentral Power Project (SPP)

The Utility entered into a participation agreement with CEA on August 28, 2008, to proceed with the joint development, construction and operation of SPP. SPP went into service on January 31, 2013. It has a capacity of 200.3 MW, of which the Utility's proportionate share is 60.1 MW, or 30%. The Utility has recorded costs of $15,097,247 and $14,895,085 in 2019 and 2018, respectively for its share of the operation of the plant. These costs include plant operation and maintenance costs and fuel expenses reported as production expenses in the Statements of Revenues, Expenses and Changes in Net Position and purchases of inventory and prepaid insurance, reported in the Statements of Net Position.

(13) Subsequent Events

(a) Sale of the Utility

On April 3, 2018, Anchorage voters approved an amendment to the Anchorage Municipal Charter authorizing the Municipality to sell the Utility to CEA by Municipal ordinance, to be approved no later than December 31, 2018. The Anchorage Assembly approved the sale on December 4, 2018. In April 2019, both the Municipality and CEA filed applications to the RCA to amend their CPCNs and to approve the sale.

On May 28, 2020, the RCA issued an order addressing the acquisition dockets and approving the sale if the parties agree to modify the transaction as required in the final order. (See Note 9(i)). At this time, CEA, the Municipality, and all the other parties in the docket have yet to decide whether they accept the conditions as ruled by the RCA. If they do accept the conditions and the acquisition goes forward, the expected closing date will be in the fall of 2020

The Utility, the Municipality and CEA are currently engaged in integration activities and transition planning. The Utility continues to operate as usual and the proposed sale has had no material effect on ongoing operations of the Utility. It is expected that the Municipality will continue to operate the Utility until the acquisition date, at which time CEA will take over operation of the Utility. Of course, the successful acquisition of most of the assets of the Utility by CEA would have a significant effect on the financial position and results of operations of the Utility. The agreement, as approved with conditions by the RCA, requires that the Utility retain only the generation assets of Eklutna Hydroelectric Project and sell power to CEA and MEA from those assets.

(b) COVID-19 Pandemic

In late January 2020, the World Health Organization ("WHO") announced a global health emergency regarding a new strain of virus called coronavirus (COVID-19). This virus originated from within China, and spread globally, including Alaska. The WHO declared this new strain creates extreme health risks as it spreads globally. Further, in March 2020, the WHO classified the coronavirus as a pandemic. March 12, 2020, the mayor of Anchorage declared a state of emergency to protect and preserve public health and safety, and subsequently closed all civic, cultural and recreational facilities in the Municipality.

Subsequent Events, continued

The governor of Alaska declared a public health disaster as did the President of the United States. The governor instituted a number of public health measures that affected intrastate and interstate travel and the movement of goods and services. The Municipality and the Utility instituted strong social distancing measures for all employees and for several weeks, many of the Utility's employees worked remotely, part-time, or were on administrative leave until safety and health procedures could be implemented to ensure that they could continue to do their jobs safely.

Management is actively monitoring the global situation and assessing its effect on the Utility's financial condition, liquidity, operations, supply chain, and workforce. Given the daily evolution of the COVID-19 outbreak and the global responses to curb its spread, the Utility is not able to estimate the effects of the COVID-19 outbreak on its results of operations, financial condition, or cash flows for fiscal year 2020.

The Utility expects a longer receivables cycle and potential reduction in commercial sales during the economic slowdown that appears to be resulting from the health emergency. The state legislature has passed legislation that could enable the Utility or its successor to recover in future rates some of the impact of unpaid utility bills and extraordinary expenses related to responding to the emergency. The legislation also provides for deferred payment agreements with customers affected by the pandemic and needing to defer payment of their electric bills to future periods. Management anticipates a negative impact on its short-term cash flows as a result of these arrangements It is possible that the pandemic will adversely impact the value of the Utility's investments held in marketable securities.

(c) ***CARES Act Funding***

On March 27, 2020 the President signed into law the "Coronavirus Aid, Relief and Economic Security (CARES) Act." The CARES Act, among other things, appropriated funds for the Coronavirus Relief Fund to be used to make payments for specified uses to States and certain local governments. There is no assurance the Utility is eligible for these funds or will be able to obtain them. The Utility continues to examine the impact that the CARES Act may have. Currently, the Utility is unable to determine the impact that the CARES Act will have on the Utility's financial condition, results of operations or liquidity.

(14) New Accounting Pronouncements

GASB has passed several new accounting standards with upcoming implementation dates. The following new accounting standards were implemented by the Utility for 2019 reporting:

- GASB 84 - *Fiduciary Activities.* No changes were required under this Statement.
- GASB 88 - Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements. This Statement requires additional disclosures for debt that fall under the definition of a direct placement and/or a direct borrowing. A direct borrowing is defined as "a government entering into a loan agreement with a lender". A direct placement is defined as "a government issuing a debt security directly to an investor". The Utility does not have any debt that is defined as a direct placement debt but has several notes and contracts that meet the definition of a direct borrowing. Additional disclosures related to debt that is defined as a direct borrowing are to be found in Note 5.
- GASB 90 - *Majority Equity Interests* - an Amendment of GASB Statements No. 14 and No. 61. The provisions of this statement were considered not applicable at this time.
- GASB 95 -*Postponement of the Effective Dates of Certain Authoritative Guidance. Due to the COVID-19 Pandemic* -the GASB Board issued GASB Statement No. 95, which postponed the effective dates of several statements which were due to be implemented during the 2020 and 2021 reporting periods. The Municipality made the decision to early implement the aforementioned GASB Statements Nos. 84, 88, and 90, as the implementation of these Statements were already completed or were not applicable at the time of the issuance of GASB 95. The remainder of the Statements affected by GASB 95 will be implemented in accordance with their new effective dates as listed below

The following standards are required to be implemented in future financial reporting periods:

- GASB 83 - *Certain Asset Retirement Obligations.* The provisions of this Statement are required to be implemented for the 2020 financial reporting period.
- GASB 87 - *Leases.* The provisions of this Statements are required to be implemented for the 2022 financial reporting period.
- GASB 89 - *Accounting for Interest Costs Incurred before the End of a Construction Period.* The provisions of this statement are required to be implemented in the 2021 reporting period.
- GASB 91 - Conduit Debt Obligations - The provisions of this statement are required to be implemented in the 2022 reporting period.
- GASB 92 - Omnibus 2020. The provisions of this statement are required to be implemented in the 2022 reporting period.

New Accounting Pronouncements, continued

- GASB 93 - Replacement of Interbank Offered Rates. The provisions of this statement are required to be implemented in the 2022 reporting period.

- GASB 94 - Public-private and Public-public Partnerships and Availability Payment Arrangements. The provisions of this statement are required to be implemented in the 2023 reporting period.

- GASB 96 - Subscription-based Information Technology Arrangements. The provisions of this statement are required to be implemented in the 2023 reporting period.

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REQUIRED SUPPLEMENTARY INFORMATION

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees' Retirement System - Defined Benefit Pension Plan
Schedule of the Utility's Proportionate Share of Net Pension Liability

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net Pension Liability(1)	Utility's Proportionate Share of the Net Pension Liability	State of Alaska's Proportionate Share of the Net Pension Liability	Total Utility Net Pension Liability	Utility's Covered Payroll	Utility's Proportionate Share of the Net Pension Liability as a Percentage of Covered Payroll	Plan Fiduciary Net Position as a Percentage of the Total Pension Liability
2019	2019	0.18440%	$ 10,094,592	$ 4,008,338	$ 14,102,930	$ 6,351,941	158.92%	63.42%
2018	2018	0.22865%	11,361,736	3,290,622	14,652,358	6,907,073	164.49%	65.19%
2017	2017	0.23737%	12,270,893	4,571,641	16,842,534	6,874,310	178.50%	63.37%
2016	2016	0.27003%	15,093,423	1,901,832	16,995,255	7,069,090	213.51%	59.55%
2015	2015	0.21637%	10,494,008	2,810,753	13,304,761	6,832,003	153.60%	63.96%

(1) The Utility's proportionate share of the Net Pension Liability represents Utility's allocated portion of the Municipality's proportionate share for the given year.

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees' Retirement System - Defined Benefit Pension Plan
Schedule of Utility Contributions

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2019	2019	$ 804,904	$ 804,904	$ -	$ 6,403,393	12.570%
2018	2018	936,339	936,339	-	6,969,518	13.435%
2017	2017	940,338	940,338	-	7,051,257	13.336%
2016	2016	854,217	854,217	-	7,204,870	11.856%
2015	2015	767,929	767,929	-	6,991,594	10.984%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees' Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of the Utility's Proportionate Share of Net OPEB Liability (Asset)

ARHCT

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net OPEB Liability(1)	Utility's Proportionate Share of the Net OPEB Liability	State of Alaska's Proportionate Share of the Net OPEB Liability	Total Utility Net OPEB Liability	Utility's Covered Payroll	Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	Plan Fiduciary Net Position as a Percentage of the Total OPEB Liability
2019	2019	0.18439%	$ 273,600	$ 108,789	$ 382,389	$ 6,351,941	4.31%	98.13%
2018	2018	0.22860%	2,346,143	681,062	3,027,205	6,907,073	33.97%	88.12%

(1) The Utility's proportionate share of the Net OPEB Liability represents the Utility's allocated portion of the Municipality's proportionate share for the given year.

RMP

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net OPEB Liability(1)	Utility's Proportionate Share of the Net OPEB Liability	State of Alaska's Proportionate Share of the Net OPEB Liability	Total Utility Net OPEB Liability	Utility's Covered Payroll	Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	Plan Fiduciary Net Position as a Percentage of the Total OPEB Liability
2019	2019	0.24273%	$ 58,071	$ -	$ 58,071	$ 6,351,941	0.91%	83.17%
2018	2018	0.26596%	33,844	-	33,844	6,907,073	0.49%	88.71%

(1) The Utility's proportionate share of the Net OPEB Liability represents the Utility's allocated portion of the Municipality's proportionate share for the given year.

ODD

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net OPEB Liability (Asset)(1)	Utility's Proportionate Share of the Net OPEB Liability (Asset)	State of Alaska's Proportionate Share of the Net OPEB Liability (Asset)	Total Utility Net OPEB Liability (Asset)	Utility's Covered Payroll	Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Covered Payroll	Plan Fiduciary Net Position as a Percentage of the Total OPEB Liability (Asset)
2019	2019	0.32582%	$ (78,996)	$ -	$ (78,996)	$ 6,351,941	-1.24%	297.43%
2018	2018	0.26596%	(51,655)	-	(51,655)	6,907,073	-0.75%	270.62%

(1) The Utility's proportionate share of the Net OPEB Liability (Asset) represents the Utility's allocated portion of the Municipality's proportionate share for the given year.

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees' Retirement System - Other Postemployment Benefit Plans (OPEB)
Schedule of Utility Contributions -

ARHCT

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2019	2019	$ 305,616	$ 305,616	$ -	$ 6,403,393	4.77%
2018	2018	303,957	303,957	-	6,969,518	4.36%

RMP

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2019	2019	$ 36,182	$ 36,182	$ -	$ 6,403,393	0.57%
2018	2018	31,365	31,365	-	6,969,518	0.45%

ODD

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2019	2019	$ 13,785	$ 13,785	$ -	$ 6,403,393	0.22%
2018	2018	11,425	11,425	-	6,969,518	0.16%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
International Brotherhood of Electrical Workers (IBEW) - Defined Benefit Pension Plan
Schedule of Utility Contributions
Last 10 Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Contractually required contribution	$ 3,249,636	$ 3,382,920	$ 3,272,545	$ 3,396,484	$ 3,059,562	$ 2,642,768	$ 2,637,978	$ 2,778,451	$ 2,649,741	$ 2,560,129
Contributions in relation to the contractually required contribution	3,249,636	3,382,920	3,272,545	3,396,484	3,059,562	2,642,768	2,637,978	2,778,451	2,649,741	2,560,129
Contribution deficiency (excess)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utility's covered payroll	$ 20,988,410	$ 21,707,594	$ 21,688,671	$ 21,965,741	$ 20,773,482	$ 19,554,891	$ 19,679,139	$ 19,988,244	$ 18,622,524	$ 17,589,819
Contribution as a percentage of covered payroll	15.48%	15.58%	15.09%	15.46%	14.73%	13.51%	13.40%	13.90%	14.23%	14.55%

See accompanying notes to Required Supplementary Information.

(1) Public Employees' Retirement System - Defined Benefit Pension Plan

In accordance with GASB Statement No. 82, "Covered Payroll" is defined as payroll on which contributions to the pension plan are based. Because a portion of the Utility's contributions to the Plan (the DBUL) are based on Defined Contribution Wages, covered payroll reported here includes all PERS participating wages (both Defined Benefit and Defined Contribution).

Both pension tables are intended to present 10 years of information. Additional years' information will be added to the schedules as it becomes available.

Schedule of Utility's Proportionate Share of the Net Pension Liability

- This table is presented based on the Plan measurement date. For December 31, 2019, the Plan measurement date is June 30, 2019.
- There were no changes in benefit terms from the prior measurement period.
- There were no changes in assumptions from the prior measurement period, except for a decrease in the Discount Rate from 8 percent in 2018 to 7.38 percent in 2019.
- There were no changes in valuation method from the prior measurement period.
- There were no changes in the allocation methodology from the prior measurement period. The measurement period ended June 30, 2019 allocated the net pension liability based on the present value of contributions for fiscal year 2020 through 2039, as determined by projections based on the June 30, 2018 actuarial valuation. This is the same allocation method used for the measurement periods ended June 30, 2018 and June 30, 2017.

The actuarial assumptions used in the June 30, 2019 actuarial valuation (latest available) were based on the results of an actuarial experience study for the period from July 1, 2013 to June 30, 2017. As a result of this experience study, the ARM Board adopted updated actuarial assumptions for the June 30, 2019 actuarial valuation to better reflect expected future experience.

Schedule of Utility Contributions

- This table is based on the Utility's contributions for each year presented. A portion of these contributions are included in the plan measurement results, while a portion of the contributions are reported as a deferred outflow of resources on the December 31, 2019 statement of net position.

(2) Public Employees' Retirement System - Defined Benefit OPEB Plans

- In accordance with GASB Statement No. 85, "Covered Payroll" is defined as payroll on which contributions to the OPEB plan are based. Because a portion of the Utility's contributions to the Plan (the DBUL) are based on Defined Contribution Wages, covered payroll reported here includes all PERS participating wages (both Defined Benefit and Defined Contribution).
- Both OPEB tables are presented for each of the three PERS OPEB plans; Alaska Retiree Healthcare Trust Plan (ARHCT), Retiree Medical Plan (RMP), and Occupational Death and Disability Plan (ODD).
- The OPEB tables are intended to present 10 years of information. Additional year's information will be added to the schedules as it becomes available.

Schedule of Utility's Proportionate Share of the Net OPEB Liability

- This table is presented based on the Plan measurement date. For December 31, 2019, the Plan measurement date is June 30, 2019.
- There were no changes in benefit terms from the prior measurement period.
- As part of the experience study, the actuarial cost method for the retiree healthcare plan was changed from the Entry Age Level Dollar method to the Entry Age Level Percent of Pay method. The Discount Rate was reduced from 8 percent in 2018 to 7.38 in 2019.
- In addition to the changes in assumptions resulting from the experience study, the following changes have been made since the prior valuation:
    - An Employee Group Waiver Plan (EGWP) was implemented effective January 1, 2019. This arrangement replaced the Retiree Drug Subsidy (RDS) under Medicare Part D and resulted in larger projected subsidies to offset the cost of prescription drug coverage.
    - Based on recent experience, the healthcare cost trend assumptions were updated.
    - Per capita claims costs were updated to reflect recent experience.
    - Healthcare cost trends were updated to reflect a Cadillac Tax load.
- There were no changes in valuation method from the prior measurement period.
- There were no changes in the allocation methodology from the prior measurement period. The measurement period ended June 30, 2019 allocated the net OPEB liability based on the present value of contributions for fiscal year 2020 through 2039, as determined by projections based on the June 30, 2018 actuarial valuation.

The actuarial assumptions used in the June 30, 2019 actuarial valuation (latest available) were based on the results of an actuarial experience study for the period from July 1, 2013 to June 30, 2017. As a result of this experience study, the ARM Board adopted updated actuarial assumptions for the June 30, 2019 actuarial valuation to better reflect expected future experience

Schedule of Utility's Contributions

- This table is based on the Utility's contributions for each year presented. A portion of these contributions are included in the plan measurement results, while a portion of the contributions are reported as a deferred outflow of resources on the December 31, 2019 statement of net position.
- All tables are intended to present 10 years' information. Additional years' information will be added to the schedule as it becomes available.

(3) International Brotherhood of Electrical Workers (IBEW) Defined Benefit Pension Plan

Schedule of Utility Contributions

- This table presents the Utility contributions for each of the last ten years based on fiscal year contributions.
- In accordance with GASB Statement No. 78, "Covered Payroll" is defined as payroll on which contributions to the pension plan are based.

STATISTICAL SECTION

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Net Position by Components
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Invested in capital assets (net of related debt)	$ 214,935,301	$ 200,317,529	$ 201,055,297	$ 215,402,069	$ 219,019,326	$ 232,279,391	$ 224,974,557	$ 241,055,196	$ 202,173,253	$ 166,889,451
Restricted for debt service	326,473	-	71,082	269,541	802,827	590,403	1,511,334	1,550,681	33,687,889	34,582,450
Restricted for interim rate escrow requirement	-	-	-	-	-	-	-	-	-	2,048,840
Restricted for operations	14,391,000	15,206,000	14,235,000	13,200,000	12,450,000	10,100,000	9,600,000	9,600,000	10,625,000	9,400,000
Unrestricted	69,669,139	69,716,192	54,095,867	25,694,823	16,500,688	12,534,565	11,790,270	(4,131,606)	(6,887,599)	20,876,436
Total net position by components	$ 299,321,913	$ 285,239,721	$ 269,457,246	$ 254,566,433	$ 248,772,841	$ 255,504,359	$ 247,876,161	$ 248,074,271	$ 239,598,543	$ 233,797,177

The Utility has prepared independent financial statements based on net position in 2015-2019. Prior to that, the Utility prepared financial statements based upon net assets from 2009-2014.
The prior years statistics have not been restated.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Change in Net Position
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Expenses:										
Production	$ 76,650,484	$ 80,038,875	$ 84,409,875	$ 75,100,243	$ 70,435,716	$ 52,745,264	$ 46,245,591	$ 49,569,470	$ 57,032,547	$ 48,356,518
Transmission	1,306,068	1,206,720	1,160,932	937,495	1,010,600	1,277,246	659,063	1,146,681	551,785	517,332
Distribution	14,596,098	13,508,019	11,609,032	11,787,913	10,868,143	10,504,929	10,138,088	9,124,625	8,352,505	7,709,097
Customer service and sales	4,260,728	4,139,729	4,285,142	4,528,685	4,022,991	3,987,004	3,939,887	4,166,844	4,171,770	4,125,907
Administrative and general	6,510,003	9,934,148	11,044,068	11,373,116	10,689,722	11,001,466	9,590,291	9,610,553	8,808,753	8,456,134
Taxes other than income	773,358	894,382	1,367,440	1,737,906	986,159	981,545	988,586	849,320	610,940	548,118
Regulatory debits (credits)	(1,642,549)	(8,026,635)	(4,028,641)	6,359,769	5,923,949	(2,264,613)	(7,121,479)	(6,163,585)	3,432,854	7,556,737
Depreciation, net of amortization	29,176,277	28,862,200	32,453,517	31,634,639	29,643,901	30,700,970	31,184,140	26,877,295	25,948,744	26,795,802
Nonoperating expenses	20,953,871	23,136,095	22,768,624	15,507,360	17,904,982	12,900,641	11,584,587	6,980,851	11,674,152	16,093,605
	152,584,338	153,693,533	165,069,989	158,967,126	151,486,163	121,834,452	107,208,754	102,162,054	120,584,050	120,159,250
Operating revenues:										
Residential sales	26,832,744	24,180,864	26,125,850	22,260,329	21,972,135	21,435,044	18,480,248	17,221,156	18,732,524	18,576,036
Commercial and industrial sales	113,371,659	103,164,976	122,670,602	106,258,842	102,566,471	98,470,914	80,954,769	70,690,478	81,243,174	81,223,012
Military sales	18,364,179	15,021,531	17,452,871	15,437,345	14,525,488	13,422,166	11,814,277	11,827,304	15,381,907	15,687,195
Sales for resale	10,803,496	28,266,428	23,344,433	15,343,153	21,890,648	7,391,906	3,652,081	16,408,646	17,053,859	9,434,212
Other operating revenues	(2,581,581)	7,084,219	(5,169,343)	7,852,729	3,181,925	(812,298)	2,066,984	3,231,506	2,006,188	4,642,456
Operating revenues	166,790,497	177,718,018	184,424,413	167,152,398	164,136,667	139,907,732	116,968,359	119,379,090	134,417,652	129,562,911
Nonoperating revenues	9,521,971	3,878,498	4,868,051	3,583,438	2,936,315	3,085,196	1,851,454	3,594,606	3,938,876	5,139,469
Total revenues	176,312,468	181,596,516	189,292,464	170,735,836	167,072,982	142,992,928	118,819,813	122,973,696	138,356,528	134,702,380
Income before transfers	23,728,130	27,902,983	24,222,475	11,768,710	15,586,819	21,158,476	11,611,059	20,811,642	17,772,478	14,543,130
Transfer to/from other funds:										
Municipal Utility Service Assessment	(9,645,938)	(9,565,771)	(9,331,662)	(5,983,574)	(7,538,022)	(7,381,413)	(5,539,711)	(5,549,734)	(5,375,710)	(5,072,546)
Transfers to other funds	-	(29,418)	-	-	(8,579)	(326,886)	(250,967)	-	-	-
Transfers from other funds	-	-	-	8,456	-	-	-	-	-	-
Dividend	-	-	-	-	(7,028,943)	(5,821,979)	(6,018,491)	(6,786,180)	(6,595,402)	(6,014,120)
Total transfers	(9,645,938)	(9,595,189)	(9,331,662)	(5,975,118)	(14,575,544)	(13,530,278)	(11,809,169)	(12,335,914)	(11,971,112)	(11,086,666)
Changes in net position	$ 14,082,192	$ 18,307,794	$ 14,890,813	$ 5,793,592	$ 1,011,275	$ 7,628,198	$ (198,110)	$ 8,475,728	$ 5,801,366	$ 3,456,464

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Capital Assets
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Capital assets:										
Steam production	$ 244,907,281	242,833,584	242,833,584	242,706,892	100,399,485	100,313,798	100,499,831	27,355,731	27,255,483	26,034,220
Hydraulic production	8,443,889	8,408,752	6,932,007	5,808,598	5,808,598	5,685,191	5,575,733	5,575,733	5,540,828	5,413,702
Other production	308,691,969	309,766,612	309,370,891	302,412,281	193,263,836	185,758,015	185,638,532	143,436,524	142,440,360	136,243,299
Transmission plant	82,696,983	82,141,081	76,759,366	73,953,864	53,003,063	50,840,731	49,638,097	38,519,353	36,105,088	36,330,641
Distribution plant	302,760,359	296,099,145	280,188,291	269,997,456	261,351,063	253,135,670	244,862,546	229,933,248	219,582,019	208,302,074
General plant	42,627,110	43,929,026	43,877,572	42,912,800	42,116,790	40,586,517	38,862,644	36,182,885	33,340,550	32,923,647
Miscellaneous intangible plant	15,034,843	14,904,003	15,116,282	10,283,951	9,439,191	8,135,695	7,966,618	7,657,794	5,790,385	5,745,486
Transmission & Mkt Ops Plant	53,744									
	1,005,216,178	998,082,203	975,077,993	948,075,842	665,382,026	644,455,617	633,044,001	488,661,268	470,054,713	450,993,069
Intangible plant	15,272,228	15,272,228	15,272,228	15,272,228	15,272,228	15,272,227	15,207,522	14,819,398	12,114,070	12,114,070
Other utility plant	-	-	-	-	-	741,167	741,167	741,167	741,167	741,167
Gas production	354,019,552	346,454,777	345,231,780	345,231,780	234,240,102	231,845,379	223,871,525	201,256,373	173,153,637	172,552,815
Total capital assets	1,374,507,958	1,359,809,208	1,335,582,001	1,308,579,850	914,894,356	892,314,390	872,864,215	705,478,206	656,063,587	636,401,121
Less accumulated depreciation for:										
Steam production	33,635,798	27,940,265	21,801,329	14,232,714	21,857,750	17,534,028	13,148,561	10,503,284	9,456,871	9,069,877
Hydraulic production	3,180,894	2,949,863	2,910,468	2,748,686	2,589,497	2,432,615	2,277,396	2,123,878	1,964,253	1,808,056
Other production	106,952,417	97,610,238	87,475,934	76,537,234	80,824,117	77,785,128	71,878,823	67,305,379	71,768,133	67,217,604
Transmission plant	20,077,881	18,669,303	17,742,318	16,586,098	15,559,845	14,866,936	14,279,448	13,555,499	12,929,380	12,668,386
Distribution plant	103,834,332	99,678,726	97,504,590	91,456,381	87,378,398	86,107,037	83,291,260	81,837,910	76,775,617	72,739,763
General plant	23,297,950	22,852,752	22,855,376	21,182,334	20,683,576	19,531,321	18,323,696	18,019,435	16,672,643	15,538,350
Miscellaneous intangible plant	15,034,843	13,670,496	11,393,594	9,850,263	8,617,566	7,270,959	5,785,215	4,406,987	3,061,171	1,909,133
Transmission & Mkt Ops Plant	1,326									
	306,015,441	283,371,643	261,683,609	232,593,710	237,510,749	225,528,024	208,984,399	197,752,372	192,628,068	180,951,169
Intangible plant	12,872,325	12,767,053	12,661,781	12,556,509	12,253,324	11,744,249	11,235,363	10,734,809	10,300,948	9,897,146
Other utility plant	-	-	-	-	-	741,167	741,167	741,167	741,167	741,167
Gas production	208,254,567	201,481,664	194,387,360	182,975,820	164,257,080	146,744,614	130,649,710	116,553,669	100,919,949	88,736,800
Total accumulated depreciation	527,142,333	497,620,360	468,732,750	428,126,039	414,021,153	384,758,054	351,610,639	325,782,017	304,590,132	280,326,282
Total capital assets, net	847,365,625	862,188,848	866,849,251	880,453,811	500,873,203	507,556,336	521,253,576	379,696,189	351,473,455	356,074,839
Construction work in progress:										
Electric	29,961,333	14,830,445	22,643,309	15,783,204	258,154,569	183,164,569	71,387,105	152,887,160	104,477,262	50,665,960
Gas	6,452	71,840	314,131	-	151,583	1,707,078	295,199	20,418,060	31,882,134	10,281,252
Total construction work in progress	29,967,785	14,902,285	22,957,440	15,783,204	258,306,152	184,871,647	71,682,304	173,305,220	136,359,396	60,947,212
Total construction work in progress and net capital assets	$ 877,333,410	877,091,133	889,806,691	896,237,015	759,179,355	692,427,983	592,935,880	553,001,409	487,832,851	417,022,051

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Comparative Operating Revenue Relationships
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Residential sales:										
Average number of customers	24,673	24,699	24,680	24,678	24,555	24,429	24,463	24,443	24,302	24,206
Total kilowatt-hour sales	115,729,851	120,098,477	127,375,339	127,731,695	130,805,337	133,411,070	139,732,855	146,789,292	143,843,977	143,472,478
Total dollar revenue	$ 26,832,744	$ 24,180,864	$ 26,125,850	$ 22,260,329	$ 21,972,135	$ 21,435,044	$ 18,480,248	$ 17,221,156	$ 18,732,524	$ 18,576,036
Average annual kilowatt-hour per customer	4,691	4,862	5,161	5,176	5,327	5,461	5,712	6,005	5,919	5,927
Average annual bill per customer	$ 1,088	$ 979	$ 1,059	$ 902	$ 895	$ 877	$ 755	$ 705	$ 771	$ 767
Average revenue per kilowatt-hour sold	0.2319	0.2014	0.2052	0.1743	0.1680	0.1606	0.1323	0.1173	0.1303	0.1294
Commercial and industrial sales:										
Average number of customers	6,403	6,407	6,388	6,398	6,373	6,358	6,319	6,300	6,297	6,271
Total kilowatt-hour sales	660,895,328	665,319,871	688,715,880	712,231,709	722,420,813	729,977,884	742,080,706	754,621,548	753,639,798	749,946,176
Total dollar revenue	$ 109,966,984	$ 100,074,769	$ 119,296,069	$ 105,104,185	$ 101,541,955	$ 97,502,022	$ 80,294,932	$ 70,118,871	$ 80,495,645	$ 80,415,527
Average annual kilowatt-hour per customer	103,217	103,843	107,814	111,321	113,356	114,813	117,436	119,781	119,682	119,590
Average annual bill per customer	$ 17,174	$ 15,620	$ 18,675	$ 16,428	$ 15,933	$ 15,335	$ 12,707	$ 11,130	$ 12,783	$ 12,823
Average revenue per kilowatt-hour sold	0.1664	0.1504	0.1732	0.1476	0.1406	0.1336	0.1082	0.0929	0.1068	0.1072
Water diversion compensation	$ 1,124,132	$ 964,797	$ 1,248,071	$ 1,154,656	$ 1,024,516	$ 968,892	$ 659,837	$ 571,607	$ 747,529	$ 807,485
Military:										
Total kilowatt-hour sales	142,528,723	141,657,828	144,968,449	147,440,533	146,817,935	145,055,072	160,954,213	194,549,942	209,515,273	210,847,451
Total dollar revenue	$ 18,364,179	$ 15,021,531	$ 17,452,871	$ 15,437,345	$ 14,525,488	$ 13,422,166	$ 11,814,277	$ 11,827,304	$ 15,381,907	$ 15,687,195
Sales for resale:										
Total kilowatt-hour sales	230,750,000	476,500,000	387,688,000	213,901,000	257,893,000	94,966,698	56,954,000	157,854,000	185,375,000	121,314,000
Total dollar revenue	$ 10,803,496	$ 28,266,428	$ 23,344,433	$ 15,343,153	$ 21,890,648	$ 7,391,906	$ 3,652,081	$ 16,408,646	$ 17,053,859	$ 9,434,212
Unmetered street lights:										
Total kilowatt-hour sales	4,274,124	4,354,949	4,430,339	4,475,018	4,452,480	4,340,094	4,702,030	4,704,154	4,643,571	4,514,322
Total dollar revenue	$ 2,280,543	$ 2,125,410	$ 2,126,462	$ 1,684,211	$ 1,662,816	$ 1,622,449	$ 1,348,286	$ 1,220,224	$ 1,258,236	$ 1,235,236
Total sales:										
Total kilowatt-hour sales	1,154,178,026	1,407,931,125	1,353,178,007	1,205,779,955	1,262,389,565	1,107,750,818	1,104,423,804	1,258,518,936	1,297,017,619	1,230,094,427
Total sales revenue	$ 169,372,078	$ 170,633,799	$ 189,593,756	$ 160,983,879	$ 162,617,558	$ 142,342,479	$ 116,249,661	$ 117,367,808	$ 133,669,700	$ 126,155,691
Average retail revenue per kilowatt-hour sold: (Residential sales and Commercial & industrial sales)										
Total dollar revenue	$ 136,799,728	$ 124,255,633	$ 145,421,919	$ 127,364,514	$ 123,514,090	$ 118,937,066	$ 98,775,180	$ 87,340,027	$ 99,228,169	$ 98,991,563
Total kilowatt-hour sales	776,625,179	785,418,348	816,091,219	839,963,404	853,226,150	863,388,954	881,813,561	901,410,840	897,483,775	893,418,654
Average retail revenue per kilowatt-hour sold	0.1761	0.1582	0.1782	0.1516	0.1448	0.1378	0.1120	0.0969	0.1106	0.1108

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2019	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 13,333,536	114,316,980
Municipality of Anchorage	6,040,278	20,305,250
Fort Richardson	5,030,643	28,211,743
Anchorage School District	4,047,387	20,963,209
Providence Alaska Medical	3,814,162	30,588,030
State of Alaska	3,671,560	23,697,709
University of Alaska, Anchorage	2,591,484	17,553,200
Providence Health System	2,422,668	16,415,009
University of Alaska	2,358,204	15,864,717
Alaska Native Tribal Health Consortium	2,204,002	17,061,774

	2018	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,171,443	117,988,033
Municipality of Anchorage	5,447,206	20,361,603
Fort Richardson	3,850,089	23,669,795
Anchorage School District	3,701,285	21,069,210
State of Alaska	3,318,240	23,499,108
Providence Alaska Medical	3,095,649	27,035,464
University of Alaska, Anchorage	2,395,975	17,497,854
Providence Alaska Medical	2,190,172	16,455,389
University of Alaska	2,152,954	16,221,798
Alaska Native Tribal Health Consortium	1,821,827	15,138,118

	2017	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 13,810,920	121,123,845
Municipality of Anchorage	6,244,068	21,997,754
Providence Alaska Medical	4,527,732	29,313,454
Anchorage School District	4,144,490	21,900,552
State of Alaska	4,055,188	24,489,039
Fort Richardson	3,641,951	23,844,604
University of Alaska, Anchorage	3,075,322	18,469,251
University of Alaska	2,762,581	16,788,893
Providence Health System	2,742,328	16,584,283
Alaska Native Tribal Health Consortium	2,625,088	16,570,118

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2016	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 12,249,880	121,923,613
Municipality of Anchorage	5,010,301	25,943,896
Providence Alaska Medical	4,047,395	30,672,310
State of Alaska	3,601,515	25,281,432
Anchorage School District	3,567,374	22,742,140
Fort Richardson	3,187,464	25,516,920
University of Alaska, Anchorage	2,583,129	18,519,071
University of Alaska	2,409,761	17,348,160
Providence Health System	2,384,436	17,182,319
Alaska Native Tribal Health Consortium	2,212,302	16,300,831

	2015	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,714,725	123,925,931
Municipality of Anchorage	4,906,357	26,544,546
Providence Alaska Medical	3,765,947	29,916,508
State of Alaska	3,559,141	26,353,330
Anchorage School District	3,520,203	23,392,075
Fort Richardson	2,810,763	22,892,004
University of Alaska, Anchorage	2,461,696	18,359,501
University of Alaska	2,304,264	17,427,455
Providence Health System	2,197,364	16,644,299
Alaska Native Tribal Health Consortium	2,172,315	16,242,233

	2014	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,017,465	125,613,900
Municipality of Anchorage	4,415,594	24,172,965
Providence Alaska Medical	3,530,551	29,596,430
State of Alaska	3,255,191	25,479,576
Anchorage School District	3,106,621	21,463,838
Fort Richardson	2,404,701	19,441,172
University of Alaska, Anchorage	2,177,227	17,079,887
Providence Health System	1,945,608	15,541,320
University of Alaska	1,913,342	15,008,522
Alaska Native Tribal Health Consortium	1,832,379	15,140,657

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

		2013	
Customer		Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$	9,226,223	131,043,824
Anchorage School District		2,897,648	24,777,425
Municipality of Anchorage		3,824,941	26,282,712
State of Alaska		2,803,076	27,544,890
Providence Alaska Medical		2,629,984	28,699,997
Fort Richardson		2,588,055	29,910,389
University of Alaska		2,072,531	20,064,980
Providence Health System		1,783,576	17,591,484
Alaska Native Tribal Health Consortium		1,589,389	16,216,071
Galen Hospital Alaska, Inc		1,571,321	16,211,245

		2012	
Customer		Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$	8,097,877	135,878,731
Fort Richardson		3,729,428	58,671,211
Municipality of Anchorage		3,422,563	26,655,434
Anchorage School District		2,655,271	26,608,898
State of Alaska		2,492,450	28,556,399
Providence Alaska Medical		2,234,908	29,596,617
University of Alaska		1,793,961	20,506,774
Providence Health System		1,514,000	17,642,498
Galen Hospital Alaska, Inc		1,386,848	16,893,051
Alaska Native Tribal Health Consortium		1,313,019	15,929,544

		2011	
Customer		Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$	9,921,072	135,333,281
Fort Richardson		5,460,835	74,181,992
Municipality of Anchorage		3,809,602	27,353,371
Providence Alaska Medical		3,116,712	29,971,840
Anchorage School District		3,015,951	26,844,664
State of Alaska		2,752,681	26,966,050
University of Alaska		2,066,234	20,226,113
Providence Health System		1,727,491	17,114,796
Galen Hospital Alaska, Inc		1,629,192	16,791,861
Alaska Native Tribal Health Consortium		1,518,934	15,702,915

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2010	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,991,880	134,772,525
Fort Richardson	5,695,316	76,074,926
Municipality of Anchorage	3,744,757	26,775,275
Anchorage School District	3,066,378	27,288,755
Providence Alaska Medical	2,871,643	29,775,325
State of Alaska	2,764,053	26,965,173
University of Alaska	2,042,255	19,973,125
Galen Hospital Alaska, Inc	1,655,862	16,844,949
Providence Health System	1,529,925	15,062,395
Alaska Native Tribal Health Consortium	1,428,740	14,679,960

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Summary

Effective date	Permanent 04/20/18	Interim 02/15/17	Permanent 07/16/15	Interim 10/24/13	Interim 03/01/13
Residential:					
Schedule 11					
Customer charge ($/month)	13.62	6.56	6.56	6.56	6.56
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.15274	0.14738	0.10734	0.10734	0.08634
Commercial:					
Schedule 21 - small commercial					
Customer charge ($/month)	30.46	12.88	12.88	12.88	12.88
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.11878	0.14161	0.10314	0.10314	0.08296
Schedule 22 - large commercial at secondary voltage					
Customer charge ($/month)	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW)	44.53	23.29	16.96	16.96	13.64
Energy charge ($/kWh)	0.00498	0.06630	0.04829	0.04829	0.03884
Schedule 23 - large commercial at primary voltage					
Customer charge ($/month)	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW)	43.10	26.18	19.07	19.07	15.34
Energy charge ($/kWh)	0.00488	0.06244	0.04548	0.04548	0.03658
Schedule 25 - replacement energy, AWWU					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.02561	0.03497	0.02547	0.02547	0.02049
Schedule 27 - interruptible power at secondary voltage					
Customer charge ($/month)	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.37673	0.06630	0.04829	0.04829	0.03884
Schedules 31, 32, 33 - general service seasonal at secondary voltage					
Customer charge ($/month) - winter	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW) - winter	-	-	-	-	-
Energy charge ($/kWh) - winter	0.11878	0.14161	0.10314	0.10314	0.08296
Customer charge ($/month) - summer	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW) - summer	44.53	23.29	16.96	16.96	13.64
Energy charge ($/kWh) - summer	0.00498	0.06630	0.04829	0.04829	0.03884
Schedules 34, 35, 36 - general service seasonal at primary voltage					
Customer charge ($/month) - winter	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW) - winter	-	-	-	-	-
Energy charge ($/kWh) - winter	0.09355	0.13502	0.09834	0.09834	0.07910
Customer charge ($/month) - summer	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW) - summer	43.10	26.18	19.07	19.07	15.34
Energy charge ($/kWh) - summer	0.00488	0.06244	0.04548	0.04548	0.03658
Area lighting/street lighting:					
Schedules 41/60 ($/month) (150 watt luminaire)	37.78	35.15	25.60	25.60	20.59
Schedules 42/61 ($/month) (175 watt luminaire)	39.74	36.97	26.93	26.93	21.66
Schedules 43/62 ($/month) (250 Watt luminaire)	44.81	41.70	30.37	30.37	24.43
Schedules 44/63 ($/month) (400 watt luminaire)	55.69	51.82	37.74	37.74	30.36
Schedules 45/64 ($/month) (1,000 watt luminaire)	101.61	94.55	68.86	68.86	55.39

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Summary

Effective date	Permanent 04/20/18	Interim 02/15/17	Permanent 07/16/15	Interim 10/24/13	Interim 03/01/13
Military:					
Schedule 700 - interruptible service - Ft. Richardson - at primary voltage					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.07245	0.05368	0.03910	0.03910	0.03145
Schedule 750 - interruptible service - Elmendorf AFB - at primary voltage					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.08428	0.06244	0.04548	0.04548	0.03658
Schedule 760 - limited all requirements service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Demand charge ($/kW)	45.43	17.36	12.64	12.64	10.17
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829
Schedule 770 - partial requirements service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Baseload demand charge ($/kW)	39.66	9.44	6.87	6.87	5.53
Peaking demand charge ($/kW)	39.66	21.42	15.60	15.60	12.55
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829
Schedule 780 - seasonal replacement service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Replacement capacity charge($/kW)	39.66	9.44	6.87	6.87	5.53
Excess demand charge ($/kW)	39.66	21.42	15.60	15.60	12.55
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Typical Monthly Bill Comparison
Last Ten Fiscal Years

		2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Residential:											
Municipal Light and Power (ML&P)	$	122.23	106.05	115.02	94.84	91.48	88.07	72.78	63.42	71.07	70.91
Chugach Electric Association (CEA)		114.57	111.36	97.55	100.87	96.63	89.78	80.77	81.89	79.23	74.17
Matanuska Electric Association Inc. (MEA)		119.99	120.52	118.81	110.11	109.70	94.46	85.60	86.61	85.56	78.21
Homer Electric Association (HEA)		147.29	141.76	139.77	137.34	137.60	131.93	113.14	108.40	115.82	96.22
Golden Valley Electric Association (GVEA)		142.25	140.83	133.44	124.36	120.88	128.94	128.64	137.98	121.05	116.29
Small commercial:											
ML&P		259.37	234.15	280.89	231.72	223.17	214.47	176.51	153.22	172.77	172.48
CEA		236.78	232.63	198.58	207.12	199.05	187.71	170.12	177.16	170.22	157.06
MEA		284.06	285.29	286.27	269.25	268.33	229.63	207.14	209.80	207.13	188.46
HEA		352.83	338.44	333.38	327.48	328.80	314.29	266.38	254.22	273.49	224.61
GVEA		340.88	332.48	313.69	290.57	281.79	302.40	301.70	325.55	282.51	270.41
Large commercial:											
Secondary:											
ML&P		6,633.43	5,865.19	7,250.48	6,001.67	5,745.19	5,484.18	4,419.30	3,801.49	4,397.47	4,399.98
CEA		6,781.08	6,649.07	5,624.11	5,880.17	5,630.91	5,268.47	4,722.87	4,916.54	4,715.59	4,311.27
MEA		7,380.81	7,341.53	7,344.33	6,751.96	6,775.04	5,672.57	5,021.80	5,147.65	5,073.38	4,527.95
HEA		9,604.15	9,188.35	9,036.26	8,991.22	9,064.48	8,651.25	7,228.33	6,890.71	7,786.51	6,314.29
GVEA		8,004.60	8,619.10	8,055.39	7,365.98	7,155.64	7,814.87	7,824.12	8,588.88	7,299.38	6,967.65
Primary:											
ML&P		34,636.38	31,347.34	41,765.37	34,752.86	33,201.74	31,623.26	25,421.68	21,806.96	25,428.81	25,472.33
CEA		39,248.47	38,526.39	32,403.60	33,943.46	32,511.01	30,425.12	27,233.03	28,524.86	27,003.61	24,526.95
MEA		0.00	0.00	36,337.67	42,034.81	42,127.05	35,408.22	31,407.40	32,208.29	31,737.59	28,412.35
HEA		40,373.55	38,498.35	37,578.59	36,637.78	37,961.74	36,426.86	28,413.23	27,513.54	38,928.11	30,271.26
GVEA		45,899.27	50,476.56	47,067.48	42,906.03	41,735.07	45,801.46	45,927.60	50,632.17	42,919.67	38,864.16

Billing determinants

	Typical customer bill	
Type of service:	kWh	kW
Residential	550	n/a
Small commercial	1,400	n/a
Large commercial, secondary	42,000	100
Large commercial, primary	254,000	500

Monthly bills include customer charge, energy charge, demand charge (where applicable), cost of power adjustment (COPA), and regulatory cost charge (RCC).
At the beginning of each quarter a typical monthly bill is calculated using rates in effect for that quarter. At the end of the calendar year a simple average of the four quarters is computed and represents a typical monthly bill for the year.

Average rates are based on current typical customer bill kWh and kW. Prior years' rates have been restated to reflect a more accurate typical customer bill kWh and kW.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Comparison
Last Ten Fiscal Years

	Average in Cents/kWh*									
	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Residential:										
ML&P	22.22	19.28	20.91	17.24	16.63	16.01	13.23	11.53	12.92	12.89
CEA	20.83	20.25	17.74	18.34	17.57	16.32	14.69	14.89	14.41	13.49
MEA	21.82	21.91	21.60	20.02	19.95	17.17	15.56	15.75	15.56	14.22
HEA	26.78	25.78	25.41	24.97	25.02	23.99	20.57	19.71	21.06	17.49
GVEA	25.86	25.60	24.26	22.61	21.98	23.44	23.39	25.09	22.01	21.14
Small commercial:										
ML&P	18.53	16.72	20.06	16.55	15.94	15.32	12.61	10.94	12.34	12.32
CEA	16.91	16.62	14.18	14.79	14.22	13.41	12.15	12.65	12.16	11.22
MEA	20.29	20.38	20.45	19.23	19.17	16.40	14.80	14.99	14.80	13.46
HEA	25.20	24.17	23.81	23.39	23.49	22.45	19.03	18.16	19.53	16.04
GVEA	24.35	23.75	22.41	20.75	20.13	21.60	21.55	23.25	20.18	19.32
Large commercial:										
Secondary:										
ML&P	15.79	13.96	17.26	14.29	13.68	13.06	10.52	9.05	10.47	10.48
CEA	16.15	15.83	13.39	14.00	13.41	12.54	11.24	11.71	11.23	10.26
MEA	17.57	17.48	17.49	16.08	16.13	13.51	11.96	12.26	12.08	10.78
HEA	22.87	21.88	21.51	21.41	21.58	20.60	17.21	16.41	18.54	15.03
GVEA	19.06	20.52	19.18	17.54	17.04	18.61	18.63	20.45	17.38	16.59
Primary:										
ML&P	13.64	12.34	16.44	13.68	13.07	12.45	10.01	8.59	10.01	10.03
CEA	15.45	15.17	12.76	13.36	12.80	11.98	10.72	11.23	10.63	9.66
MEA	0.00	0.00	14.31	16.55	16.59	13.94	12.37	12.68	12.50	11.19
HEA	15.90	15.16	14.79	14.42	14.95	14.34	11.19	10.83	15.33	11.92
GVEA	18.07	19.87	18.53	16.89	16.43	18.03	18.08	19.93	16.90	15.30

Average rate comparisons, when expressed in cents per kWh, are derived by dividing the typical monthly bill by the kWh's (See Typical Monthly Bill Comparison) used to calculate the bill for each class and multiplying the result by 100 to convert to cents per kWh.

Average rates are based on current typical customer bill kWh and kW. Prior years' rates have been restated to reflect a more accurate typical customer bill kWh and kW.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)

Bond Debt

Principal and Interest (cash basis)

	Senior lien electric revenue bonds		
Year	Principal	Interest	Total
2020	$ 8,075,000	16,603,147	24,678,147
2021	8,410,000	16,268,347	24,678,347
2022	8,760,000	15,917,897	24,677,897
2023	9,200,000	15,479,897	24,679,897
2024	9,635,000	15,042,772	24,677,772
2025 - 2029	55,420,000	66,936,195	122,356,195
2030 - 2034	69,545,000	49,398,028	118,943,028
2035 -2039	87,430,000	27,022,900	114,452,900
2040 - 2044	51,300,000	6,625,600	57,925,600
	$ 307,775,000	229,294,783	537,069,783

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Schedule of Revenue Bond Coverage
Last Ten Fiscal Years

Fiscal Year	Revenue (1)(2)	Operating Expenses (3)	Net Revenue Available for Debt Service	Debt Service Requirement (accrual basis) Principal (4)	Interest (2)(4)	Total Debt Service	Coverage (5)
2019	$ 173,869,422	$ 113,742,677	$ 60,126,745	$ 7,730,000	$ 14,507,701	$ 22,237,701	*2.70*
2018	179,159,110	119,287,644	59,871,466	7,865,000	14,875,691	22,740,691	*2.63*
2017	186,859,566	119,179,510	67,680,056	7,520,000	15,197,731	22,717,731	*2.98*
2016	168,290,963	117,808,701	50,482,262	7,465,000	15,561,997	23,026,997	*2.19*
2015	164,652,279	111,475,302	53,176,977	7,440,000	15,868,460	23,308,460	*2.28*
2014	140,578,329	85,614,254	54,964,075	17,910,000	10,719,674	28,629,674	*1.92*
2013	116,439,242	69,979,738	46,459,504	17,085,000	10,684,851	27,769,851	*1.67*
2012	122,973,354	73,853,642	49,119,712	16,915,000	13,953,484	30,868,484	*1.59*
2011	138,326,743	88,336,864	49,989,879	16,945,000	14,969,376	31,914,376	*1.57*
2010	134,571,665	82,342,389	52,229,276	16,995,000	15,974,962	32,969,962	*1.58*

(1) Excludes interest charged to construction and interest restricted for construction.
(2) Excludes Federal subsidy for 2015 through 2019
(3) Includes Municipal Service Assessment per Municipal Ordinance AO 83-58 and excludes depreciation.
(4) 2014 Principal and Interest do not include the debt service for 1996 Senior Lien Bonds defeased during the year.
(5) The required minimum revenue bond coverage is 1.35 and the all-debt minimum coverage is 1.10.
Notes payable are not reflected on this schedule. If it were included, all-debt coverage for fiscal years 2019 and 2018 would be 1.73 and 1.70, respectively.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Statement of Net Position Ratios
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Current ratio	4.09	4.14	2.90	0.43	0.47	0.94	0.37	0.67	3.54	3.72
This ratio is a measure of the Utility's ability to meet short-term obligations. The current ratio is calculated by dividing current assets by current liabilities.										
Long-term debt/gross plant	27 / 73	28 / 72	28 / 72	28 / 72	29 / 71	27 / 73	25 / 75	24 / 76	23 / 77	27 / 73
This ratio provides the gross plant value represented by long-term debt. It is an indication of how much leverage has been utilized in acquiring plant assets.										
Debt/Equity (Net Position)	63 / 37	64 / 36	66 / 34	67 / 33	65 / 35	59 / 41	56 / 44	52 / 48	50 / 50	52/48
This ratio expresses the relationship of gross debt to net position as components of the total capital structure (excluding net pension liability and including commercial paper).										
Return on net position (excluding dividend)	4.82%	6.63%	5.68%	2.33%	3.15%	5.43%	2.35%	6.37%	5.30%	4.11%
This ratio is a measure of the return received on net position. The return on net position is calculated by dividing the change in net position, (excluding dividend and special item) by net position.										
Operating margin	21.08%	26.54%	22.84%	14.17%	18.62%	22.14%	18.25%	20.27%	18.98%	19.68%

The operating margin ratio expresses the percentage of each dollar of operating revenue that represents operating income. The ratio is calculated as operating income divided by operating revenue.

The utility started preparing independent financial statements based on net position in 2013 and based on net assets from 2007 to 2012. The prior years have not been restated in the statistical section.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Base Ratings by Generation Units
As of December 31, 2019

Type	Unit no.	Base rating 30F (MW)	Base rating ISO (MW)	Nameplate capacity (KVA)
Combustion turbine	3	32.9	29.3	48,941
Combustion turbine	4	33.6	31.1	31,765
Combustion turbine	7	81.8	74.4	110,556
Combustion turbine	8	85.0	77.3	102,941
Combustion turbine	9	48.9	48.5	71,000
Combustion turbine	10	48.9	48.5	71,000
Steam turbine	11	28.9	28.9	36,000
Sub-total		360.0	338.0	472,203
Hydro-turbine (Eklutna)	1	22.2	22.2	22,222
Hydro-turbine (Eklutna)	2	22.2	22.2	22,222
Sub-total		44.4	44.4	44,444
Steam Turbine (SPP)	10	57.5	38.1	67,647
Cumbustion Turbine (SPP)	11	47.6	40.2	57,352
Cumbustion Turbine (SPP)	12	47.6	40.2	57,352
Cumbustion Turbine (SPP)	13	47.6	40.2	57,352
Sub-total		200.3	158.7	239,703
Total		604.7	541.1	756,350
ML&P units		360.0	338.0	472,203.0
Eklutna (53.3%)		23.7	23.7	23,688.7
SPP (30%)		60.1	47.6	71,910.9
		443.8	409.3	567,802.6
Plant 1		66.5	60.4	80,706
Plant 2		293.5	277.6	391,497
Eklutna		23.7	23.7	23,689
SPP		60.1	47.6	71,911

International Standards Organization (ISO)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Generated and Purchased Power (Kilowatt Hours)
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Hank Nikkels Plant 1										
Maximum generator nameplate capacity in Kilovolt Ampere (KVA)	80,706	80,706	80,706	80,706	111,956	111,956	111,956	111,956	111,956	111,956
Net peak demand on plant (kilowatts for 60 minutes)	57,000	57,000	59,000	55,000	57,000	56,000	69,000	58,000	70,000	60,000
Plant hours connected to load	1,103	1,720	3,248	2,165	2,331	1,730	1,676	2,531	3,942	2,653
Net generation kilowatt hours (kwh)	16,476,441	28,937,168	50,849,000	45,082,278	47,782,296	33,642,939	22,223,799	54,633,112	91,338,507	55,427,594
George M. Sullivan Plant 2										
Maximum generator nameplate capacity in (KVA)	213,497	213,497	213,497	213,497	291,542	291,542	291,542	291,542	291,542	291,542
Net peak demand on plant (kilowatts for 60 minutes)	74,000	99,000	100,000	144,000	162,000	116,000	147,000	182,000	201,000	210,000
Plant hours connected to load	899	1,417	2,733	14,771	16,841	14,594	17,166	25,062	24,856	25,837
Net generation (kwh)	25,940,927	62,521,710	107,834,000	589,737,560	654,788,840	493,717,440	562,282,640	1,011,487,040	1,082,362,200	1,048,416,040
Plant 2A										
Maximum generator nameplate capacity in (KVA)	178,000	178,000	178,000	178,000	-	-	-	-	-	-
Net peak demand on plant (kilowatts for 60 minutes)	125,000	123,000	122,000	53,000	-	-	-	-	-	-
Plant hours connected to load	20,013	22,792	21,646	627	-	-	-	-	-	-
Net generation (kwh)	599,118,425	781,700,477	699,634,000	16,186,000	-	-	-	-	-	-
Southcentral Power Plant (the Utility's entitlement is 30%)										
Maximum generator nameplate capacity in (KVA)	239,703	239,703	239,703	239,703	239,703	239,703	239,703	-	-	-
Net peak demand on plant (kilowatts for 60 minutes)	180,000	180,000	188,000	193,000	198,000	200,570	197,000	-	-	-
Plant hours connected to load	33,884	34,115	33,290	34,674	33,042	34,118	30,476	-	-	-
Net generation (kwh)	372,027,000	389,111,000	372,998,000	373,982,000	338,331,000	392,146,000	376,802,000	-	-	-
Eklutna Hydro Project (the Utility's entitlement is 53.33%)										
Maximum generator nameplate capacity in (KVA)	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444
Net peak demand on plant (kilowatts for 60 minutes)	40,000	40,000	40,000	40,100	43,000	41,600	41,900	41,400	41,800	41,600
Plant hours connected to load	12,476	14,179	12,020	16,964	16,510	16,525	16,975	17,092	16,460	15,083
Net generation (kwh)	190,971,348	168,114,718	119,916,900	168,902,714	135,428,052	156,688,891	171,456,687	144,596,206	127,446,166	129,197,695
The utility's actual net generation received (kwh)	111,891,000	67,827,000	55,029,418	69,403,457	68,552,565	83,110,070	88,671,274	71,163,019	66,107,871	74,203,136
Off Site Generation										
Chugach Electric Assoc. (kwh)	-	-	-	-	15,501,000	-	-	-	-	300,000
Purchased Power										
Alaska Energy Authority (kwh)	66,345,000	102,307,000	95,933,060	90,390,272	117,013,000	127,651,000	80,928,000	116,925,000	78,661,000	79,441,000
Chugach Electric Assoc. (kwh)	-	-	-	-	1,590,000	-	-	-	-	-

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Energy Loads and Resources
Last Ten Fiscal Years

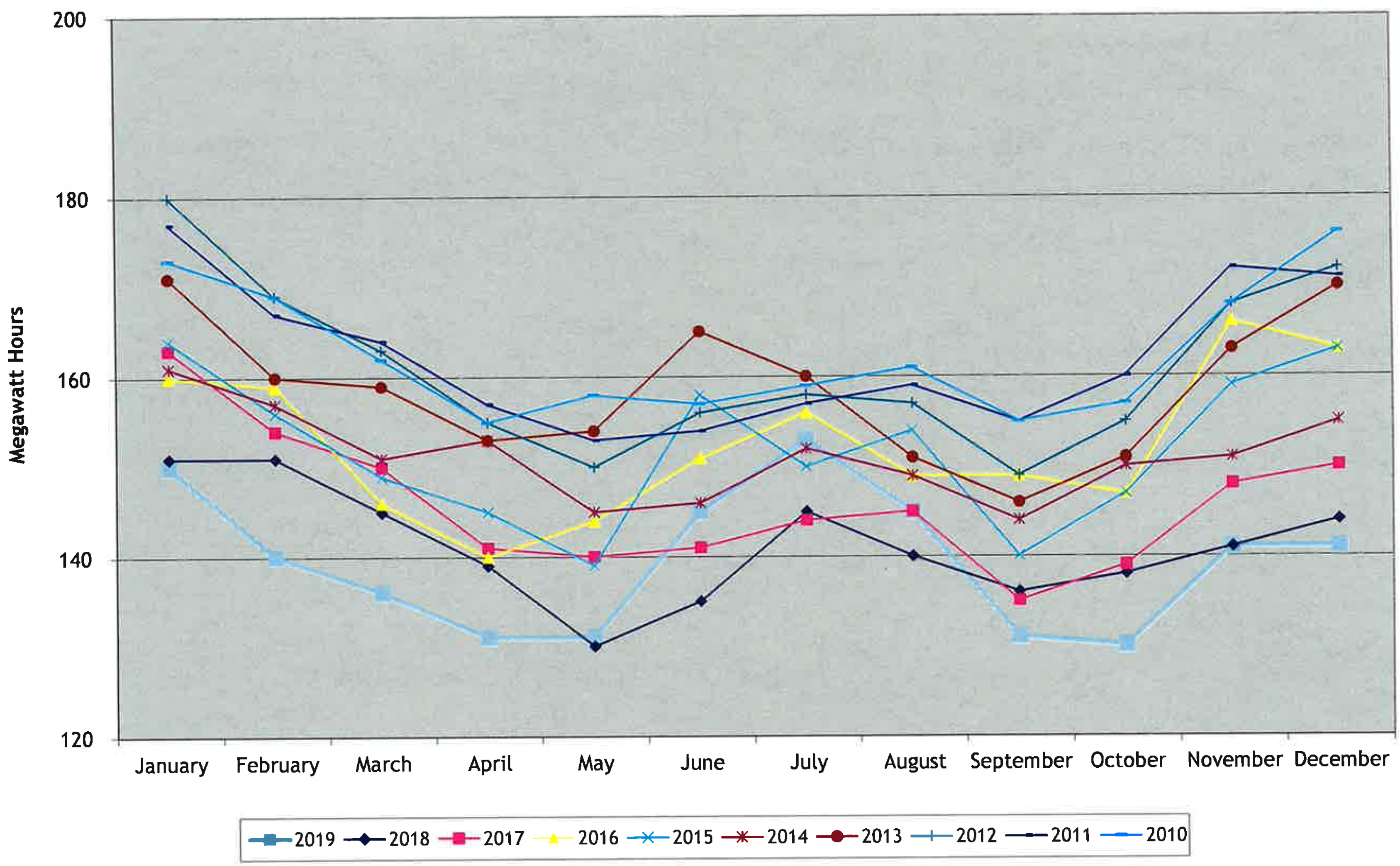
	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Sales to Customers: MWH										
Residential	115,730	120,098	127,375	127,731	130,805	133,411	139,733	146,789	143,844	143,473
Commercial	660,895	665,320	688,716	712,232	722,421	729,977	742,081	754,622	753,640	749,946
Other	146,803	146,013	149,399	151,916	151,270	149,395	165,656	199,254	214,159	215,361
Sales for Resale	230,750	476,500	387,688	213,901	257,893	94,967	56,954	157,854	185,375	121,314
Total Energy Sales	1,154,178	1,407,931	1,353,178	1,205,780	1,262,389	1,107,750	1,104,424	1,258,519	1,297,018	1,230,094
System Losses and Owner Use	61,680	58,947	59,072	50,792	50,589	38,745	46,397	36,743	43,125	49,579
Total Energy Requirements	1,215,858	1,466,878	1,412,250	1,256,572	1,312,978	1,146,495	1,150,821	1,295,262	1,340,143	1,279,673
Energy Resources:										
Own Resources	1,149,513	1,364,571	1,316,317	1,166,182	1,194,375	1,018,844	1,069,893	1,178,337	1,261,482	1,199,932
Other	66,345	102,307	95,933	90,390	118,603	127,651	80,928	116,925	78,661	79,741
Total Energy Resources	1,215,858	1,466,878	1,412,250	1,256,572	1,312,978	1,146,495	1,150,821	1,295,262	1,340,143	1,279,673

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Monthly Peak (Megawatt Hours)
Last Ten Fiscal Years

Month	Year									
	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
January	150	151	163	160	164	161	171	180	177	173
February	140	151	154	159	156	157	160	169	167	169
March	136	145	150	146	149	151	159	163	164	162
April	131	139	141	140	145	153	153	155	157	155
May	131	130	140	144	139	145	154	150	153	158
June	145	135	141	151	158	146	165	156	154	157
July	153	145	144	156	150	152	160	158	157	159
August	145	140	145	149	154	149	151	157	159	161
September	131	136	135	149	140	144	146	149	155	155
October	130	138	139	147	147	150	151	155	160	157
November	141	141	148	166	159	151	163	168	172	168
December	141	144	150	163	163	155	170	172	171	176

MUNICIPALITY OF ANCHORAGE
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)

Monthly Peak (Megawatt Hours)
Last Ten Fiscal Years



MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Miscellaneous Statistical Information
Last Ten Fiscal Years

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Number of customers	31,082	31,112	31,074	31,081	30,932	30,751	30,767	30,747	30,603	30,481
Number of street lights	3,794	3,837	3,879	3,891	3,897	3,901	3,911	3,924	3,930	3,948
Circuit miles of overhead distribution line	113	114	118	118	120	122	123	124	125	130
Miles of underground distribution line	289	250	253	253	253	254	248	250	252	257
Plant generation capacity (30 degrees fahrenheit) - KW	443,780	443,780	443,780	444,260	395,470	395,470	395,470	364,500	364,500	364,500

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Independent Auditor's Report on Internal Control Over Financial Reporting and on Compliance and Other Matters Based on an Audit of Financial Statements Performed in Accordance With *Government Auditing Standards*

Honorable Mayor and Members of the Assembly
Municipality of Anchorage, Alaska

We have audited, in accordance with the auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the financial statements of the Electric Utility Fund, an enterprise fund of the Municipality of Anchorage, Alaska, as of and for the year ended December 31, 2019, and the related notes to the financial statements, which collectively comprise the Electric Utility Fund's basic financial statements, and have issued our report thereon dated June 30, 2020.

Internal Control Over Financial Reporting

In planning and performing our audit of the financial statements, we considered the Electric Utility Fund's internal control over financial reporting (internal control) to determine the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Electric Utility Fund's internal control. Accordingly, we do not express an opinion on the effectiveness of the Electric Utility Fund's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis. *A significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies. Given these limitations, during our audit we did not identify any deficiencies in internal control that we consider to be material weaknesses. However, material weaknesses may exist that have not been identified.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Electric Utility Fund's financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the entity's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Electric Utility Fund's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

BDO USA, LLP

Anchorage, Alaska
June 30, 2020

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
A Major Enterprise Fund of the Municipality of Anchorage

Financial Statements,
Required Supplementary Information
and
Other Information

December 31, 2018 and 2017

(With Independent Auditor's Report Thereon)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

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3601 C Street, Suite 600
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Independent Auditor's Report

Honorable Mayor and Members of the Assembly
Municipality of Anchorage, Alaska

Report on the Financial Statements

We have audited the accompanying financial statements of the Electric Utility Fund, an enterprise fund of the Municipality of Anchorage, Alaska, as of and for the years ended December 31, 2018 and 2017, and the related notes to the financial statements, which collectively comprise the Electric Utility Fund's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards,* issued by the Comptroller General of the United States. 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 the auditor's 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, the auditor considers internal control relevant to the entity'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 entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of the 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 the Electric Utility Fund as of December 31, 2018 and 2017, and the changes in financial position and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matters

As discussed in Note 1, the financial statements present only the Electric Utility Fund, and do not purport to, and do not present fairly the financial position of the Municipality of Anchorage, Alaska as of December 31, 2018 and 2017, the changes in its financial position, or where applicable, its cash flows for the years ended in accordance with accounting principles generally accepted in the United States. Our opinion is not modified with respect to this matter.

Change in Accounting Principle

As discussed in Note 2 to the accompanying financial statements, in 2018 the Electric Utility Fund adopted the provisions of Governmental Accounting Standards Board (GASB) Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*. Our opinion was not modified with respect to this matter.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that Management's Discussion and Analysis on pages 4 through 15 and other required supplementary information on pages 77 through 87 be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements that collectively comprise the Electric Utility Fund's basic financial statements. The statistical section is presented for purposes of additional analysis and is not a required part of the basic financial statements. The statistical section has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated June 30, 2019 on our consideration of the Electric Utility Fund's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Electric Utility Fund's internal control over financial reporting and compliance.

BDO USA, LLP

Anchorage, Alaska
June 30, 2019

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Management's Discussion and Analysis

December 31, 2018 and 2017

The Electric Utility Fund (Utility) is a public utility of the Municipality of Anchorage (Municipality or Anchorage). The following is a discussion and analysis of the Utility's financial performance, providing an overview of the financial activities for the years ended December 31, 2018 and 2017. This discussion and analysis is designed to assist the reader in focusing on the significant financial issues, provide an overview of the Utility's financial activities and identify changes in the Utility's financial position. We encourage readers to consider the information presented here in conjunction with the Utility's financial statements and accompanying notes, taken as a whole.

Financial Highlights

- The Utility's total plant decreased $12.7 million or 1.4% in 2018 while decreasing $6.4 million or 0.7% in 2017. The decrease in 2018 and 2017 was due to depreciation exceeding additions.
- Total assets and deferred outflows of resources exceeded total liabilities and deferred inflows of resources by $285.2 million at December 31, 2018 and by $269.5 million at December 31, 2017. Of these amounts, $69.7 million in 2018 and $54.1 million in 2017 were unrestricted and available to meet the Utility's ongoing obligations to customers and creditors.
- The Utility's total net position increased $15.8 million or 5.86% in 2018, compared to an increase of $14.9 million or 5.85% in 2017. The increase in net position in 2018 was primarily due to lower fuel costs and a lower gas transfer price for internally produced gas. Depreciation also decreased significantly in 2018. Beginning net position was reduced by $2.5 million due to adoption of a new accounting standard in 2018. The increase in net position in 2017 was primarily due to a full year of a new rate structure as well as a full year of operating Generation Plant 2A.

Overview of the Financial Statements

The Utility is a business type activity of the Municipality that provides electrical services to a specific area of the Municipality. The Utility's activities are recorded in an enterprise fund of the Municipality.

Required Financial Statements

The Utility's financial statements offer short and long-term information about the activities of the Utility and collectively provide an indication of the Utility's financial health. The basic financial statements are prepared using the economic resources measurement focus and accrual basis of accounting.

The basic financial statements, presented on a comparative basis for the years ended December 31, 2018 and 2017, include Statements of Net Position, Statements of Revenues, Expenses, and Changes in Net Position and Statements of Cash Flows.

The *Statements of Net Position* present information on all of the Utility's assets, liabilities, deferred outflows of resources and deferred inflows of resources, with the difference reported as net position, and provides information about the nature and amounts of investments in resources and obligations to creditors.

The *Statements of Revenues, Expenses, and Changes in Net Position* report operating and non-operating revenues and expenses, and the change in net position of the Utility for the years presented.

The *Statements of Cash Flows*, using the direct method of presentation, provide information about the Utility's cash receipts and cash payments during the years presented. These statements report cash and cash-equivalent activities for each fiscal year resulting from operating activities, noncapital financing activities, capital and related financing activities, and investing activities. These statements also provide answers to such questions as, where did cash come from, what was cash used for, and what was the change in cash balance during the reporting period.

The *Notes to Financial Statements* provide the reader with additional information that is essential to a full understanding of the data provided in the basic financial statements.

The *Required Supplementary Inform*ation presents certain information concerning the progress in funding the Utility's obligation to provide pension and other postemployment benefits.

Financial Analysis of the Utility

One of the most important questions asked about the Utility's finances is whether the Utility, as a whole, is better or worse off as a result of the year's activities. The Statements of Net Position and the Statements of Revenues, Expenses, and Changes in Net Position report information about the Utility's activities in ways that will help answer this question. These two statements report the net position of the Utility and changes in net position for each of the years presented. You can think of the Utility's net position, the difference between assets, deferred outflows of resources, liabilities, and deferred inflows of resources as one way to, over time, provide a measure of the Utility's financial health or financial position. Over time, increases or decreases in the Utility's net position can indicate whether its financial health is improving or deteriorating. However, you will need to also consider other non-financial factors such as changes in economic conditions and customer growth, as well as legislative and regulatory mandates.

The Utility's total net position increased $18.3 million from beginning net position, as restated, during 2018 compared to an increase in net position of $14.9 million during 2017. The following analysis focuses on the Utility's net position and changes in net position during the year.

A portion of the Utility's net position (70.3% and 74.7% as of December 31, 2018 and 2017, respectively) reflects its net investment in capital assets, such as gas and electric production, transmission and distribution facilities, less any related outstanding debt used to acquire those assets. Those capital assets are used to provide services to customers; consequently those assets are not available for future spending or to be used to liquidate any outstanding debt.

An additional portion of the Utility's net position (5.3% and 5.3% as of December 31, 2018 and 2017 respectively) represent resources that are subject to external restriction for debt repayment and future operations.

The unrestricted portion of the Utility's net position (24.4% and 20.0% as of December 31, 2018 and 2017, respectively) are available to be used to meet the Utility's obligations to creditors and customers.

Net Position

	December 31, 2018	December 31, 2017	December 31, 2016
Plant	$ 877,091,133	889,806,691	896,237,015
Restricted assets	69,889,012	108,827,334	74,769,608
Current and other assets	118,134,761	90,519,572	96,052,728
Deferred outflows of resources	1,961,254	1,372,834	3,865,199
Total assets and deferred outflows of resources	1,067,076,160	1,090,526,431	1,070,924,550
Current and other liabilities	27,027,209	40,360,462	228,959,153
Non-current liabilities	549,844,293	556,863,095	373,195,399
Deferred inflows of resources	204,964,937	223,845,628	214,203,565
Total liabilities and deferred inflows of resources	781,836,439	821,069,185	816,358,117
Net investment in capital assets	200,317,529	201,055,297	215,402,069
Restricted for debt service	-	71,082	269,541
Restricted for operations	15,206,000	14,235,000	13,200,000
Unrestricted	69,716,192	54,095,867	25,694,823
Total net position	$ 285,239,721	269,457,246	254,566,433

Notable components of changes in assets, liabilities, and deferred inflows and outflows of resources are discussed below.

Plant decreased $12.7 million during 2018 compared to a decrease of $6.4 million during 2017.

During 2018 construction work in progress decreased by $8.1 million, compared to an increase of $7.2 million in 2017 as a result of capital projects started in prior years, completed in 2018.

During 2017 construction work in progress increased by $7.2 million, compared to a decrease of $242.5 million in 2016. Due to the completion of major capital projects in 2016, change in construction work in progress in 2017 is representative of a more typical year.

Restricted assets decreased $38.9 million during 2018 compared to an increase of $34.0 million during 2017.

During 2018 the Regulatory Commission of Alaska (RCA) allowed the Utility to remove the restriction on $40.6 million in cash collected due to the rate increase and the Utility repaid $9.1 million in tax credits received in prior years from the State of Alaska.

In February 2017, the RCA granted the Utility an interim and refundable rate increase of 37.30%. An interim rate escrow was established for the purpose of restricting the refundable rate increase collected from customers.

Current and other assets increased $27.6 million during 2018 compared to a decrease of $5.5 million during 2017.

During 2018 the Utility's equity in general cash pool increased by $29.3 million due to lifting of the restriction of funds collected from customers pursuant to the refundable rate increase granted by the RCA. Other receivables decreased by $1.7 million due to timing of payment of receivables. Prepaid items decreased $2.2 million due to accelerated payments in 2017 for purchased power.

During 2017 the Utility's equity in general cash pool decreased by $14.7 million primarily due to the restriction of funds collected from customers pursuant to the refundable rate increase granted by the RCA. Other receivables increased by $5.8 million primarily due to end of the year economy energy sales of electricity. Inventories of materials and supplies increased by $1.8 million primarily due to an increase in gas stored at Cook Inlet Natural Gas Storage and additional materials purchased for Generation Plant 2A.

Deferred outflows of resources increased $0.6 million during 2018 and decreased $2.5 million in 2017 as a result of changes in pension related items and accounting for other postemployment benefits.

Current and other liabilities decreased $13.3 million during 2018 compared to a decrease of $188.6 million during 2017.

During 2018 accounts payable from current assets decreased $12.5 million primarily due to repaying prior year over-recovery of cost of power expenses from customers.

During 2017 short-term debt decreased $181.0 million due to reclassification of notes payable to long-term debt. Accounts payable from restricted assets decreased $6.1 million because the Utility expended all of its proceeds from short-term debt completing Generation Plant 2A.

Non-current liabilities decreased $7.0 million during 2018 compared to a decrease of $183.7 million in 2017.

During 2018 the primary driver of the change was a $0.9 million reduction in pension liability, the addition of $2.3 million in other postemployment benefits (OPEB) liability due to adoption of new accounting standards, and $7.9 million redemption of bonds.

During 2017 the primary driver of the change was the reclassification of $191.9 million in notes payable from short-term to long-term, offset by a decrease of $2.8 million in the net pension liability and $7.5 million redemption of bonds.

Deferred inflows of resources decreased $18.9 million in 2018 compared to an increase of $9.6 million in 2017.

During 2018 contributions in aid of construction decreased by $2.8 million due to amortization in 2018 exceeding additions. Deferred inflows of resources related to pensions decreased $0.7 million while deferred inflows of resources related to other postemployment benefits of $0.8 million were recorded due to the adoption of a new accounting standard. The future natural gas purchases account increased by $0.7 million in investment earnings and redemption of intercompany debt. Future BRU construction or natural gas purchases account decreased by $16.9 million primarily due to refunding tax credits offset by $2.2 million in gas sales and $0.1 million in investment earnings (see Note 9 (c)).

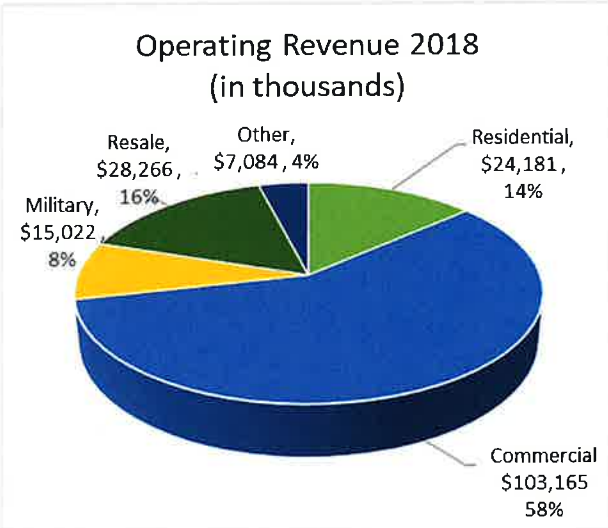
During 2017 contributions in aid of construction increased by $3.3 million due to the transfer of $9.0 million from non-contributed to contributed plant as a result of an RCA order, offset by amortization. Deferred inflows of resources related to pensions changed $0.8 million. The future natural gas purchases account increased by $0.8 million in investment earnings and redemption of intercompany debt. Future BRU construction or natural gas purchases account increased by $4.8 million. There were $16.3 million in gas sales and $0.2 million in investment earnings (see Note 9 (c)).

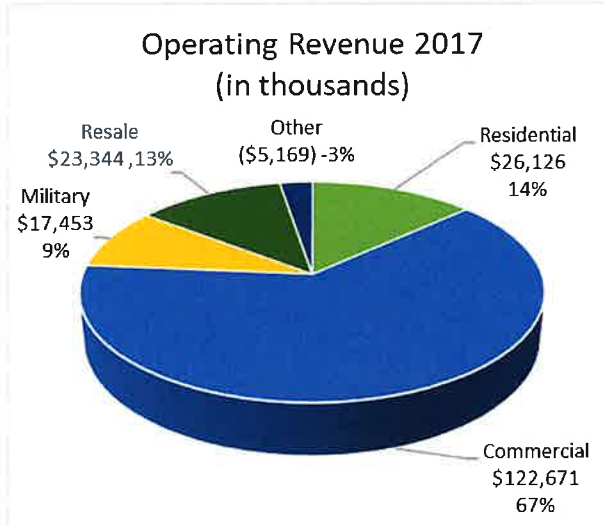
Revenues, Expenses, and Changes in Net Position

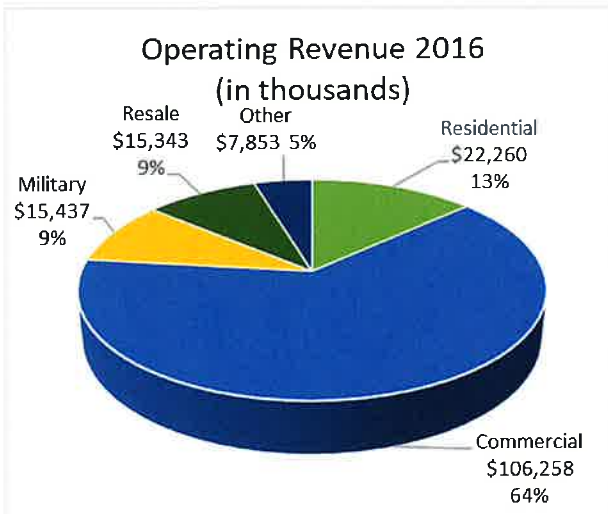
Changes in the Utility's net position can be determined by reviewing the following condensed schedule of revenues, expenses, and changes in net position for the years ended December 2018, 2017, and 2016:

		Years ended December 31,		
		2018	2017	2016
Operating revenues:				
Residential sales	$	24,180,864	26,125,850	22,260,329
Commercial and industrial sales		103,164,976	122,670,602	106,258,842
Military sales		15,021,531	17,452,871	15,437,345
Sales for resale		28,266,428	23,344,433	15,343,153
Other operating revenues		7,084,219	(5,169,343)	7,852,729
Operating revenues		177,718,018	184,424,413	167,152,398
Nonoperating revenues		3,878,498	4,868,051	3,533,982
Total revenues		181,596,516	189,292,464	170,686,380
Expenses:				
Production		80,038,875	84,409,875	75,100,243
Transmission		1,206,720	1,160,932	937,495
Distribution		13,508,019	11,609,032	11,787,913
Customer service and sales		4,139,729	4,285,142	4,528,685
Administrative and general		9,934,148	11,044,068	11,373,116
Regulatory debits (credits)		(8,026,635)	(4,028,641)	6,359,769
Taxes other than income		894,382	1,367,440	1,737,906
Depreciation, net of amortization		28,862,200	32,453,517	31,634,639
Operating expenses		130,557,438	142,301,365	143,459,766
Nonoperating expenses		23,136,095	22,768,624	15,457,904
Total expenses		153,693,533	165,069,989	158,917,670
Income before transfers		27,902,983	24,222,475	11,768,710
Transfers:				
Municipal Utility Service Assessment (MUSA)		(9,565,771)	(9,331,662)	(5,983,574)
Transfers (to)/from other funds		(29,418)	-	8,456
Change in net position		18,307,794	14,890,813	5,793,592
Beginning net position (restated)		266,931,927	254,566,433	248,772,841
Ending net position	$	285,239,721	269,457,246	254,566,433

Revenues by Source:







Total revenues decreased $7.7 million during 2018 compared to an increase of $18.6 million during 2017. Total kilowatt hours (kWh) sold increased by 54.8 million in 2018 compared to an increase of 147.3 million in 2017. Components of the changes in revenues were:

During 2018 total operating revenues were $177.7 million, a decrease of $6.7 million from 2017. Military sales revenue decreased by $2.4 million. Commercial and industrial sales decreased by $19.5 million while sales for resale increased by $4.9 million during the year. Retail sales decreases were primarily due to lower Cost of Power Adjustment (COPA.) revenues as a result of lower fuel costs for the year and more efficient generation assets. Other operating revenues increased by $12.3 million due to under-recovery of COPA. Non-operating revenues decreased by just under $1 million due to lower investment income as a result of fewer assets invested.

During 2017 total operating revenues were $184.4 million, an increase of $17.3 million from 2016 primarily due to rate increases implemented in February 2017. The largest growth was in commercial and industrial sales, which increased $16.4 million. Increases of $3.9 million in residential sales, $2 million in military sales, and $8 million in sales for resale were offset by a decrease of $13 million in other operating revenues. Other operating revenues decreased $13 million due to over-recovery of COPA. Non-operating revenues increased by $1.3 million primarily due to investment gains.

Expenses by Category

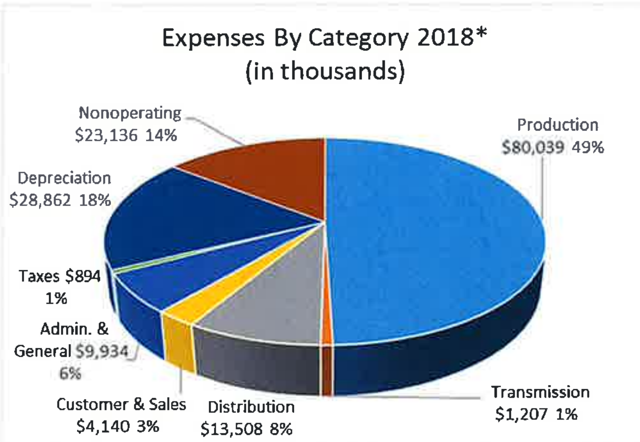
Total expenses by category decreased $11.4 million during 2018 compared to an increase of $6.2 million during 2017. Components of the changes were:

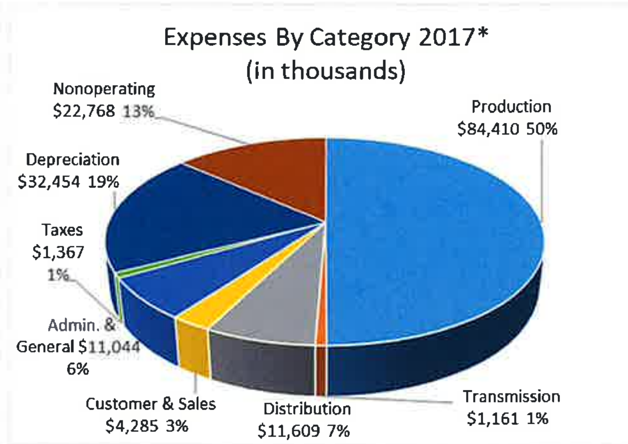
During 2018 operating expenses decreased $11.7 million from 2017 due to a $4.4 million decrease in production expenses (primarily fuel),and a $4 million increase in regulatory credits due to repayment of over-collection of COPA from customers. Distribution expenses increased by $1.9 million, administrative and general expenses decreased $1.1 million; depreciation expenses decreased $3.6 million primarily due to retirement of assets. Non-operating expenses increased just $0.4 million primarily due to increased short-term borrowing costs offset by decreases in other miscellaneous, interest expenses and loss on disposal of property.

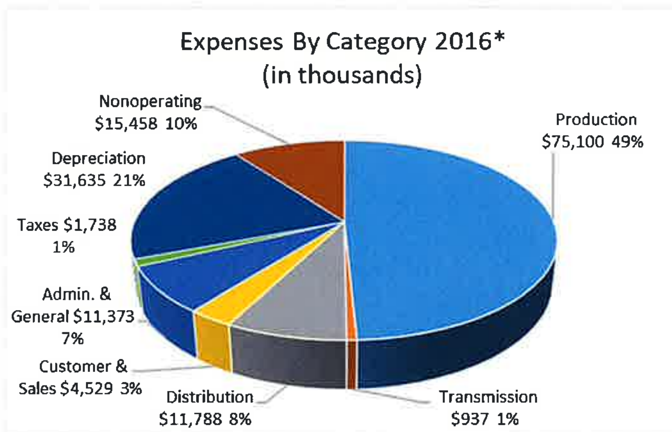
MUSA, which represents payments to the municipal government in lieu of property taxes, remained consistent with 2017, increasing just $0.2 million due to a decrease in plant assets and an increase in mill rates.

During 2017 operating expenses decreased $1.1 million from 2016, mainly due to a $9.3 million increase in production expenses offset by a $10.4 million increase in regulatory credits. Production increased mainly because more fuel was used by the Utility for increased sales of electricity for resale, and regulatory credits reflect an over-collection of COPA from customers during the year. Non-operating expenses increased $7.3 million primarily due to a $12 million decrease in allowance for funds used during construction (AFUDC), a $0.2 million increase in interest expense on long-term obligations, and a $0.6 million increase in other interest due to an increase in interest rates, offset by a $6 million decrease in loss on disposal of property.

MUSA increased $3.3 million over 2016, due to the increase in plant value when Generation Plant 2A was placed in service in late 2016.





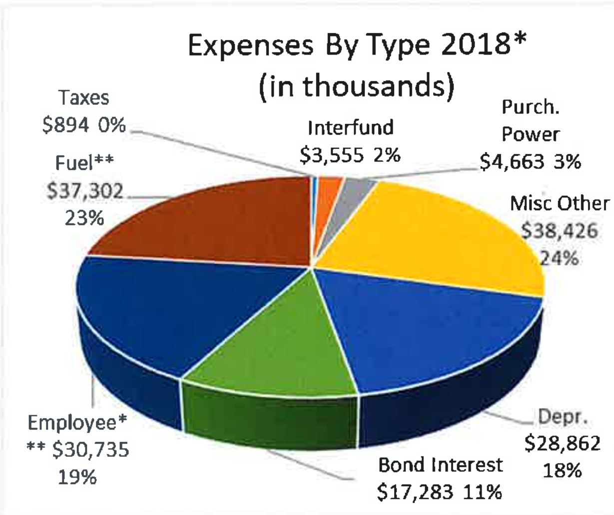


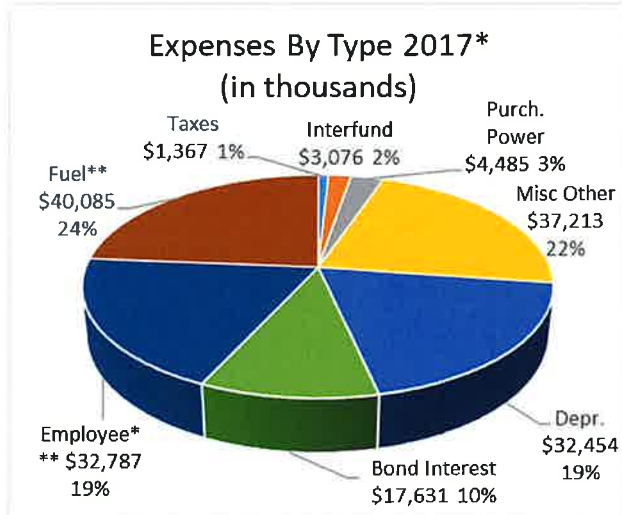
* Expenses by category excluding regulatory debits (credits)

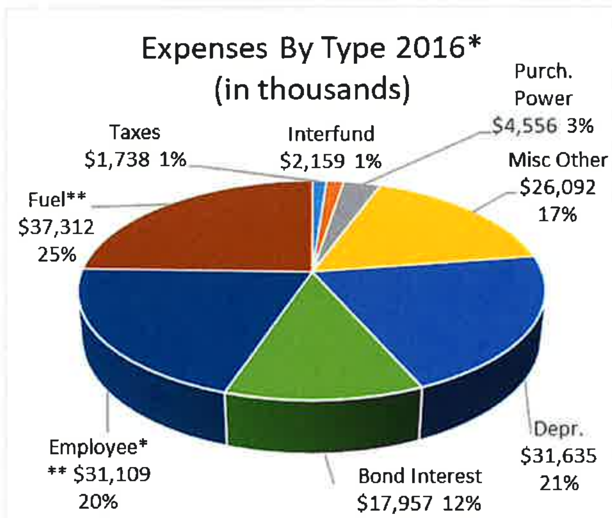
MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Management's Discussion and Analysis

December 31, 2018 and 2017







*Expenses by type excluding regulatory debits (credits)

**Fuel expense includes purchased natural gas, transportation costs, diesel fuel used, and CINGSA.

***Employee expense includes general liability and workers compensation insurance.

Capital Assets - Plant

The Utility's investment in capital assets as of December 31, 2018 and 2017 was $877.1 million and $889.8 million, respectively (net of accumulated depreciation and depletion.) This included investments in gas and electric production, transmission and distribution related facilities, as well as general items such as buildings and vehicles. Plant decreased 1.43% and 0.72% over the prior year for 2018 and 2017, respectively.

The Utility's capital assets as of December 31, 2018, 2017, and 2016 were as follows:

	2018	2017	2016
Capital assets:			
Steam production	$ 242,833,584	242,833,584	242,706,892
Hydraulic production	8,408,752	6,932,007	5,808,598
Other production	309,766,612	309,370,891	302,412,281
Transmission plant	82,141,081	76,759,366	73,953,864
Distribution plant	296,099,145	280,188,291	269,997,456
General plant	43,929,026	43,877,572	42,912,800
Miscellaneous intangible plant	14,904,003	15,116,282	10,283,951
Intangible plant	15,272,228	15,272,228	15,272,228
Gas production	346,454,777	345,231,780	345,231,780
Total capital assets	1,359,809,208	1,335,582,001	1,308,579,850
Total accumulated depreciation	(497,620,360)	(468,732,750)	(428,126,039)
Total construction work in progress	14,902,285	22,957,440	15,783,204
Net capital assets	$ 877,091,133	889,806,691	896,237,015

For further information regarding the Utility's capital assets, see Note 4.

Long Term Debt - Revenue Bonds and Notes Payable

As of December 31, 2018 and 2017, the Utility had outstanding long-term debt of $524 and $534 million, respectively.

The Utility's long term-debt as of December 31, 2018, 2017, and 2016, were as follows:

		2018	2017	2016
Revenue bonds:				
Series 2005A	$	12,150,000	17,565,000	22,705,000
Series 2009A		15,240,000	15,240,000	15,240,000
Series 2009B		114,760,000	114,760,000	114,760,000
Series 2014A		173,355,000	175,805,000	178,185,000
Unamortized discount		(446,018)	(476,692)	(507,779)
Unamortized premium		17,436,399	18,721,619	20,104,669
Total revenue bonds		332,495,381	341,614,927	350,486,890
Notes payable		191,900,000	191,900,000	-
Total long-term debt	$	524,395,381	533,514,927	350,486,890

Notes payable were reclassified from short-term to long-term in 2017. Notes payable increased $10.9 million during 2017 as Generation Plant 2A construction was concluded.

Bond Rating

At December 31, 2018, the Utility maintains the following underlying credit ratings:

Standard & Poor's	A+
Fitch	A+

In May 2018, Standard & Poor's reaffirmed the A+ rating of the Utility's Senior Debt. In September 2018, Fitch reaffirmed the A+ rating of the Utility's Senior Debt.

Budgetary Highlights

On November 21, 2017, an ordinance adopting and appropriating funds for the 2018 Municipal Utilities' Operating and Capital Budgets for the Municipality was approved. The Utility's operating budget was $169,464,144 and the capital budget was $57,105,000, which includes $11 million for the BRU. The Utility's 2018 actual appropriated expenses of $134,490,309 were $35.0 million or 20.6% under the budget. Capital expenditures for plant improvements totaled $23 million.

On October 9, 2018, an ordinance adopting and appropriating funds for the 2019 Municipal Utilities' Operating and Capital Budgets for the Municipality was approved. The Utility's operating budget was $159,217,263 and the capital budget was $42,020,000, which includes $9.6 million for the BRU.

On April 9, 2019 a resolution amending the Utility's 2019 operating budget by $0.8 million was approved by the Municipal Assembly; the Utility's total revised operating budget for 2019 increased to $160 million.

Economic Factors and Rates

Sale of the Utility

On April 3, 2018, Anchorage voters approved an amendment to the Anchorage Municipal Charter authorizing the Municipality to sell the Utility to Chugach Electric Association (CEA) by Municipal ordinance. An asset purchase and sale agreement has been approved by the Anchorage Municipal Assembly and CEA's board of directors. The Utility and CEA have both filed petitions with the RCA to approve the acquisition. A successful acquisition of most of the assets of the Utility by CEA would have a significant effect on the financial position and results of operations of the Utility. The petitions, as filed, request that the Utility retain only the generation assets of Eklutna and sell power to CEA from those assets. (See Note 9(i) and Note 11).

Contacting the Utility's Financial Management

This financial report is designed to provide our customers, citizens, and creditors with a general overview of the Utility's finances and to demonstrate the Utility's accountability for the money it receives. If you have any questions about this report or need additional financial information, contact the Utility's Chief Financial Officer, Mollie C. Morrison, at (907) 263-5205.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Net Position

December 31, 2018 and 2017

Assets and Deferred Outflows of Resources	**2018**	**2017**
Plant:		
Plant in service, at cost	$ 1,344,536,980	1,320,309,773
Less accumulated depreciation and depletion	484,853,307	456,070,969
Net plant in service	859,683,673	864,238,804
Intangible plant, net	2,505,175	2,610,447
Construction work in progress	14,902,285	22,957,440
Total plant	877,091,133	889,806,691
Restricted assets:		
Current:		
Restricted equity in general cash pool - customer deposits	1,225,452	1,186,226
Interim rate escrow investment	-	27,250,254
Noncurrent:		
Debt service investment	2,058,443	2,098,515
Revenue bond reserve investment	23,718,574	23,335,229
Revenue bond operations and maintenance investment	15,206,000	14,235,000
Future natural gas purchases investment	5,732,181	3,811,326
Future BRU construction or natural gas purchases investment	8,032,509	23,711,907
Asset retirement obligation sinking fund investment	13,915,853	13,198,877
Total restricted assets	69,889,012	108,827,334
Current assets:		
Equity in general cash pool	61,906,365	32,591,181
Net accounts receivable:		
Utility customers, less estimated uncollectibles of $214,282 in 2018 and $182,731 in 2017	8,319,226	8,601,943
Other receivables, less estimated uncollectibles of $77,082 in 2018 and $67,508 in 2017	7,306,860	9,031,977
Accrued interest	736,000	646,359
Unbilled reimbursable projects	131,864	110,625
Inventory of materials and supplies, at average cost	31,388,131	32,077,195
Prepaid Items	861,556	3,043,135
Total current assets	110,650,002	86,102,415
Other assets:		
Non-current:		
Unamortized regulatory assets	6,147,029	2,967,188
Unamortized debt expense	1,337,730	1,449,969
Total other assets	7,484,759	4,417,157
Total assets	1,065,114,906	1,089,153,597
Deferred outflows of resources:		
Deferred loss on refunding	61,057	248,700
Deferred outflows related to pensions	1,155,512	1,124,134
Deferred outflows related to other postemployment benefits	744,685	-
Total deferred outflows of resources	1,961,254	1,372,834
Total assets and deferred outflows of resources	$ 1,067,076,160	1,090,526,431

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Net Position, continued

December 31, 2018 and 2017

Liabilities, Deferred Inflows of Resources and Net Position		**2018**	**2017**
Current liabilities (payable from current assets):			
Accounts payable	$	12,035,116	24,493,095
Compensated absences payable		2,526,423	2,812,140
Accrued payroll liabilities		1,506,814	1,775,992
Accrued interest		1,813,590	1,688,922
Other liabilities		189,814	27,300
Pollution remediation liability		-	511,787
Long-term obligations maturing within one year		7,730,000	7,865,000
Total current liabilities (payable from current assets)		25,801,757	39,174,236
Current liabilities (payable from restricted assets):			
Customer deposits		1,225,452	1,186,226
Non-current liabilities:			
Notes payable		191,900,000	191,900,000
Asset retirement obligation		16,543,712	15,823,732
Unearned revenue		948,181	864,531
Net pension liability		11,361,736	12,270,893
Net other postemployment benefits liability		2,328,332	-
Obligation for undergrounding		1,996,951	2,254,012
Revenue bonds payable after one year, net of premium and discount		324,765,381	333,749,927
Total non-current liabilities		549,844,293	556,863,095
Total liabilities		576,871,502	597,223,557
Deferred inflows of resources:			
Contributions in aid of construction (net of amortization)		177,823,955	180,608,877
Future natural gas purchases		17,934,651	17,230,809
Future BRU construction or natural gas purchases		8,077,741	25,002,529
Deferred inflows related to pensions		285,157	1,003,413
Deferred inflows related to other postemployment benefits		843,433	-
Total deferred inflows of resources		204,964,937	223,845,628
Net position:			
Net investment in capital assets		200,317,529	201,055,297
Restricted for debt service		-	71,082
Restricted for operations		15,206,000	14,235,000
Unrestricted		69,716,192	54,095,867
Total net position		285,239,721	269,457,246
Total liabilities, deferred inflows of resources and net position	$	1,067,076,160	1,090,526,431

See accompanying notes to basic financial statements.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Revenues, Expenses and Changes in Net Position
For the Years Ended
December 31, 2018 and 2017

	2018	2017
Operating revenues:		
Residential sales	$ 24,180,864	26,125,850
Commercial and industrial sales	103,164,976	122,670,602
Military sales	15,021,531	17,452,871
Sales for resale	28,266,428	23,344,433
Other operating revenues	7,084,219	(5,169,343)
Total operating revenues	177,718,018	184,424,413
Operating expenses:		
Production	80,038,875	84,409,875
Transmission	1,206,720	1,160,932
Distribution	13,508,019	11,609,032
Customer service and sales	4,139,729	4,285,142
Administrative and general	9,934,148	11,044,068
Regulatory credits	(8,026,635)	(4,028,641)
Taxes other than income	894,382	1,367,440
Depreciation, net of amortization	28,862,200	32,453,517
Total operating expenses	130,557,438	142,301,365
Total operating income	47,160,580	42,123,048
Nonoperating revenues:		
Investment income	1,197,610	2,098,199
Interest subsidy on Build America Bonds	2,437,406	2,432,899
PERS on behalf	154,073	336,953
OPEB on behalf	89,409	-
Total nonoperating revenues	3,878,498	4,868,051
Nonoperating expenses:		
Interest:		
Long-term obligations	16,794,977	17,104,164
Other interest	4,429,858	2,561,257
Total interest	21,224,835	19,665,421
Allowance for funds used during construction	(638,303)	(525,306)
Amortization of other assets	157,027	286,133
Loss on disposal of property	2,337,536	2,808,232
Other nonoperating expenses	55,000	534,144
Total nonoperating expenses	23,136,095	22,768,624
Net nonoperating revenues (expenses)	(19,257,597)	(17,900,573)
Income before transfers	27,902,983	24,222,475
Transfers:		
Municipal Utility Service Assessment	(9,565,771)	(9,331,662)
Transfers to other funds	(29,418)	-
Total transfers	(9,595,189)	(9,331,662)
Change in net position	18,307,794	14,890,813
Net position - beginning of year, as restated	266,931,927	254,566,433
Net position - end of year	$ 285,239,721	269,457,246

See accompanying notes to basic financial statements.

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Cash Flows
For the Years Ended
December 31, 2018 and 2017

	2018	2017
Cash flows from operating activities:		
Receipts from customers and users	$ 182,289,020	198,440,556
Other operating cash receipts	11,919,963	2,867,451
Payments to employees	(36,114,203)	(30,847,671)
Payments to vendors	(106,426,580)	(92,866,543)
Internal activity - payments made to other funds	(4,217,349)	(2,394,475)
Net cash provided by operating activities	47,450,851	75,199,318
Cash flows from noncapital financing activities:		
Transfer - Municipal Utility Service Assessment	(9,565,771)	(9,331,662)
Transfers to other funds	(29,418)	-
Net cash used by noncapital and related financing activities	(9,595,189)	(9,331,662)
Cash flows from capital and related financing activities:		
Proceeds from issuance of short-term debt	-	10,900,000
Interest payments on short-term debt	(4,429,858)	(2,561,257)
Principal payments on long-term debt	(7,865,000)	(7,520,000)
Interest and debt issuance cost payments on long-term debt	(17,781,999)	(18,277,114)
Interest subsidy on Build America Bonds	2,436,538	2,432,899
Acquisition and construction of capital assets	(20,599,776)	(32,336,702)
Contributed capital - customers	273,528	647,401
Contributed capital - intergovernmental agencies	521,344	337,787
Payments for interfund services used	(1,142,414)	(2,200,583)
Proceeds from sale of property	-	7,934
Net cash used by capital and related financing activities	(48,587,637)	(48,569,635)
Cash flows from investing activities:		
Net (deposits to) withdrawals from restricted funds	11,727,294	(9,317,829)
Investment income received	1,108,837	2,014,395
Net cash provided (used) by investing activities	12,836,131	(7,303,434)
Net increase in cash	2,104,156	9,994,587
Cash, beginning of year	61,027,661	51,033,074
Cash, end of year	$ 63,131,817	61,027,661
Cash and cash equivalents:		
Equity in general cash pool	$ 61,906,365	32,591,181
Interim rate escrow investment	-	27,250,254
Restricted equity in general cash pool	1,225,452	1,186,226
Cash and cash equivalents, end of year	$ 63,131,817	61,027,661

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Cash Flows, continued
For the Years Ended
December 31, 2018 and 2017

		2018	2017
Reconciliation of operating income to net cash provided by operating activities:			
Operating income	$	47,160,580	42,123,048
Adjustments to reconcile operating income to net cash provided (used) by operating activities:			
Depreciation, net of amortization		28,862,200	32,453,517
PERS on behalf		154,073	336,953
OPEB on behalf		89,409	-
Allowance for uncollectible accounts		41,125	66,838
Other nonoperating expenses		(55,000)	(534,144)
Changes in assets and liabilities which increase (decrease) cash:			
Accounts receivable		1,966,709	(5,471,201)
Unbilled reimbursable projects		(21,239)	776,795
Inventories		689,064	(1,815,450)
Prepaid items		2,181,579	(1,485,296)
Unamortized regulatory assets		(3,179,841)	(1,322,364)
Deferred outflows of resources related to pensions		(31,378)	2,224,158
Deferred outflows of resources related to other postemployment benefits		(568,875)	-
Accounts payable		(13,876,244)	(5,788,651)
Compensated absences payable		(285,717)	(162,189)
Accrued payroll liabilities		(269,178)	270,422
Other liabilities		162,514	(243,015)
Customer deposits		39,226	15,497
Asset retirement obligation		719,980	688,646
Unearned revenue		83,650	339,447
Net pension liability		(909,157)	(2,822,530)
Net other postemployment benefits liability		489,294	-
Obligation for undergrounding		(257,061)	97,338
Deferred inflows of resources		(14,997,948)	14,616,328
Deferred inflows of resources related to pensions		(718,256)	835,171
Deferred inflows of resources related to other postemployment benefits		(18,658)	-
Total cash provided by operating activities	$	47,450,851	75,199,318
Non-cash investing, capital and financing activities:			
Capital purchases on account	$	906,478	571,394
Portion of plant from allowance for funds used during construction		638,303	525,306
Contributions in aid of construction funded from deferred inflows of resources		1,222,998	9,097,137
Total non-cash investing, capital and financing activities	$	2,767,779	10,193,837

See accompanying notes to basic financial statements.

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(1) Description of Business and Summary of Significant Accounting Policies

The first electric system serving Anchorage was installed in 1916 by the Alaska Engineering Commission, the agency of the United States Department of the Interior which constructed the Alaska Railroad. A small steam plant and several diesel power generators supplied Anchorage with electricity until 1929 when the private Anchorage Power and Light Company began supplying the community with electricity from a hydroelectric power plant on the Eklutna River located 15 miles northeast of downtown Anchorage. The Alaska Engineering Commission distribution system was purchased by Anchorage in 1932. Anchorage then acquired the Eklutna plant from the Anchorage Power and Light Company in 1943. This is what is now Anchorage Municipal Light and Power or the Electric Utility Fund, a public utility of the Municipality of Anchorage. The Utility now has six turbine generating units fired by natural gas and one heat recovery steam turbine generating unit. The Utility also has a thirty percent ownership in Southcentral Power Project and fifty-three and one-third percent ownership interest in the Eklutna Hydroelectric Project and is entitled to twenty-five and nine-tenths percent of the output of the Bradley Lake Hydroelectric Project. The Utility meets the majority of its natural gas requirements from its ownership interest in the Beluga River Gas Field, including the initial one-third interest acquired in December 1996. The Utility's goal in acquiring the working interest in the BRU was to lock in a critical resource for the long-term and provide a hedge against anticipated future increases in natural gas prices. During 2016 the Utility acquired 70% of a one-third working interest in the field from ConocoPhillips Alaska, Inc.(CPAI), increasing its working interest to 56.67%.

The accompanying financial statements include the activities of the Utility. The Utility is a major enterprise fund of the Municipality and not the Municipality as a whole. The Utility is subject to the regulatory authority of the RCA.

The Utility applies all applicable provisions of the Governmental Accounting Standards Board (GASB) which has authority for setting accounting standards for governmental entities. The accounting records of the Utility conform to the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Accounting and reporting treatment applied to the Utility is accounted for on a flow of economic resources measurement focus using the accrual basis of accounting. Revenues are recognized when they are earned and expenses are recognized at the time liabilities are incurred. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with the Utility's principal ongoing operations. All other revenues and expenses are reported as non-operating.

(a) Regulated Operations

The Utility meets the criteria, and accordingly follows the accounting and reporting requirements applicable to regulated operations. The Utility's rates are regulated by the RCA and as a result, revenues intended to recover certain costs are provided either before or after the costs are incurred, resulting in regulatory assets or liabilities. The following regulatory assets and liabilities are reflected in the accompanying financial statements:

- The Utility receives contributions in aid of construction, which it records as contributed plant in service and a deferred inflow of resources. The Utility amortizes contributed plant and the deferred inflow of resources over the useful life of the utility plant.
- The Utility accepted a monetary settlement in 2015 from its BRU partners for its 2014 underlift. The Utility used these funds to reduce its Gas Transfer Price (GTP) from July 1, 2016 through June 30, 2017. See Note 9(a).
- The Utility has a regulatory asset or liability account to capture the difference in the cost of power and revenue received through the Cost of Power Adjustment (COPA). See Note 9(b).
- The Utility has a regulatory asset or liability account to capture the difference in the amount of the Gas Fund revenue requirement and the actual amount of revenue collected from the Electric Fund. See Note 9(b).
- The Utility records proceeds from the sales of gas, net of royalties, taxes and an Asset Retirement Obligation (ARO) surcharge, as a deferred regulatory liability, reported as deferred inflows of resources on the statements of net position. See Note 9(c).
- The Utility funds ARO expenses associated with future abandonment of the BRU through a surcharge to the Utility's GTP, which is deposited into a sinking fund. See Note 9(c) and (d).

Management believes that the recorded amounts of all regulatory assets are fully recoverable from ratepayers in the future.

(b) Management Estimates

In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and deferred outflows of resources, liabilities and deferred inflows of resources and the reporting of contingent assets and liabilities as of the date of the statement of net position and revenues and expenses for the period. Actual results could differ from those estimates. The more significant accounting and reporting policies and estimates applied in the preparation of the accompanying financial statements are discussed below.

(c) Cash Pools and Investments

The Municipality uses a central treasury to account for all cash and investments to maximize interest. Interest income on cash pool investments is distributed based on the average daily balance in the general cash pool. The Utility's investments are reported at fair value in the financial statements.

(d) *Statements of Cash Flows*

For purposes of the statements of cash flows, the Utility has defined cash as the demand deposits and all investments maintained in the general cash pool, regardless of maturity period, since the Utility uses the cash pools essentially as demand deposit accounts. Restricted assets in the general cash pool, except for customer deposits, have not been included in the definition of cash.

(e) ***Restricted Assets***

Certain proceeds of the Utility's revenue bonds, as well as resources set aside for their repayment, are classified as restricted assets on the statements of net position because their use is limited by applicable bond covenants. The revenue bond reserve investment account is used to report resources set aside to augment potential deficiencies from Utility operations that could adversely affect debt service payments. The debt service account is used to segregate resources accumulated for debt service payments over the next twelve months. The revenue bond operations and maintenance account represents funds set aside to comply with bond covenants requiring a reserve equal to one-eighth of the preceding year's operating expenses (as defined in the bond covenants).

The restricted equity in general cash pool-customer deposits account represents deposits provided by electric service customers as security for bill payment. Future natural gas purchases or BRU construction and ARO sinking funds are funds for which the RCA has specified the use.

Interim revenue escrow investments are funds collected from customer sales arising from interim and refundable rates granted by the RCA. The restriction on those funds was lifted on June 1, 2018 by the RCA following the submittal of tariff sheets in compliance with RCA Order No. 13 in U-17-008. (See Note 9(e).)

(f) Inventories

Inventories are valued at weighted average cost. The cost of inventories are recorded as expenditures when consumed rather than when purchased. Inventories consist of parts and materials used to maintain or build new transmission, distribution, and generation facilities. Scrap and nonusable materials in inventory are carried at net estimated realizable value until sold or otherwise disposed of.

The Utility also stores natural gas in a depleted field on the Kenai Peninsula. Cook Inlet Natural Gas Storage Alaska (CINGSA) started in 2012 and as of December 31, 2018 the Utility has stored 6.74 billion cubic feet of gas.

(g) Property, Plant and Equipment

Electric

Capital assets are stated at cost. Depreciation is computed by use of the straight-line method over the estimated economic life of the asset. Additions to electric plant in service are at original cost of items such as contracted services, direct labor and materials, indirect overhead charges and AFUDC. The Utility capitalizes general plant assets valued at more than $25,000 that have an expected life in excess of one year. Contributed assets are recorded at the cost incurred by the Utility for the addition of such assets. Donated assets are recorded at acquisition value. Acquisition value is the price that would be paid to acquire an asset with equivalent service potential in an orderly market transaction at the acquisition date. For property replaced or retired, the cost of the property unit, plus removal costs less salvage, is charged to accumulated depreciation. Gain or loss is not recognized unless the Utility determines that such costs could not be recovered in rates. Costs for maintenance and repairs are expensed as incurred, except for major maintenance on generation assets, for which costs are collected into a regulatory asset and amortized over the period of utility, generally three to five years.

Estimated lives of major plant and equipment categories follow:

Production plant	24 - 60 years
Hydraulic plant	40 - 45 years
Transmission plant	45 - 60 years
Distribution plant	17 - 55 years
General plant - buildings	40 - 60 years
Vehicles	16 - 20 years
Other general plant	5 - 20 years
Original gas field acquisition	23 years
Intangible plant	5 - 30 years

Gas

Acquisition costs, the costs of wells, related equipment and facilities initially acquired as part of the 1996 acquisition of a one-third working interest in the BRU were, as a result of a regulatory proceeding and subsequent order by the RCA, being depleted at 125% of the principal payments on the debt used to finance the acquisition of this asset. Those assets were fully depleted at December 31, 2018, as related debt was fully redeemed at December 1, 2018.

The acquisition of assets purchased with designated underlift settlement funds are being amortized using the units of production method, based upon proven reserves in accordance with the amortization method used for regulatory purposes. The acquisition of assets purchased with gas sale proceeds, and assets acquired from CPAI in the 2016 purchase, are being recorded as contributed plant and are being amortized using the units of production method, based on proven reserves in accordance with the amortization method used for regulatory purposes.

(h) Unbilled Revenues and Accounts Receivable

Electric revenues are based on cycle billings rendered to customers monthly. As a result of this cycle billing method, the Utility does not accrue revenue at the end of any fiscal period for services sold but not billed at such date. The unbilled revenues for the Utility are immaterial. An allowance for doubtful accounts is provided for receivables where there is a question of collectability. Utility receivables are presented in the statements of net position net of estimated uncollectible amounts. Gas sales are calculated based upon volumes delivered and recorded as a regulatory liability, which is reported as deferred inflows of resources on the statements of net position (see Note 9(c)).

(i) Gas Balancing

The Utility has elected to account for underlifted gas from its ownership interest in the BRU according to the sales method. Therefore, the financial statements do not include a receivable or revenue for underlifted volumes for which the Utility did not elect to receive cash settlement. As of December 31, 2018 and 2017, the underlift balance was 23,106 and 172 Mcf, respectively. The Utility also has the option per the Gas Balancing Agreement to take cash settlements for any underlifted gas.

(j) Asset Retirement Obligation (ARO)

The Utility accounts for its ARO for its interest in the BRU in accordance with Accounting Standards Codification (ASC) Topic #410-20, formerly Statement of Financial Accounting Standards No 143, *"Accounting for Asset Retirement Obligations" (SFAS No 143)* and 18 CFR 101 General Instruction No 25, *Accounting for Asset Retirement Obligations (Regulations of the Federal Energy Regulatory Commission, Department of Energy, or FERC)*. ASC 410-20 and FERC General Instruction No 25 applies to the fair value of a liability for an ARO that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition of: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

In 2012 the Utility made its initial recording of the ARO asset and ARO liability with a beginning balance of $1,461,335 representing the fair value of the obligation at 1996 - the period when the obligation was incurred. The Utility recorded in 2012 $4,185,549 to the ARO liability representing total accretion expense that would have been incurred if the liability was accreted from the time the obligation was incurred through December 31, 2012. During 2013, the Utility commissioned a study of the costs associated with abandoning the BRU field and as a result of the findings of that study, adjusted the ARO liability and accretion as of December 2013. On April 22, 2016, the Utility purchased 70% of CPAI's one-third interest in the BRU. At that time a revised estimate was made of the life of the gas field. The Utility's obligation for an ARO was adjusted for the increased liability and changes in estimated life and discount rate. As of December 31, 2016, the Utility entered into an agreement with the State of Alaska Department of Natural Resources (DNR) to establish an ARO investment fund to meet its obligations for dismantling, removing and restoring the land and property to a condition acceptable to the commissioner of the DNR in accordance with the terms and conditions of assigned leases and applicable statutes and regulations.

A schedule of changes in the ARO balance for the years ending December 31, 2018 and 2017 is as follows:

		2018	2017
Asset to be retired:		Gas Field	
Beginning carrying value	$	15,823,732	15,135,086
Current year changes to the liability balance		-	-
Current year settled		-	-
Current year accretion		719,980	688,646
Change in assumption or cash flow revisions		-	-
Ending ARO	$	16,543,712	15,823,732

(k) *Discount or Premium on Revenue Bonds Payable*

The discount or premium on revenue bonds payable is amortized over the life of the related bond issues using the effective interest method.

(l) *Compensated Absences*

The Utility records employee leave, which includes sick leave, when earned.

(m) *Deferred Outflows and Inflows of Resources*

The Utility enters into transactions that result in the consumption or acquisition of resources in one period that are applicable to future periods. These consumptions and acquisitions of resources are reported in the statements of net position as deferred outflows and inflows of resources, respectively. The Utility records deferred outflows of resources related to pensions and other postemployment benefits, and deferred loss on refunding of bonds, and deferred inflows of resources related to pensions and other postemployment benefits, contributions in aid of construction and certain items related to the operation of the BRU.

(n) *Net Position*

The Utility's net position is categorized as net investment in capital assets, restricted or unrestricted. The Utility's restricted net position represents assets restricted for payment of debt service, or restricted for operations, in accordance with covenants of the related revenue bond indentures. It is the Utility's policy to evaluate whether to use restricted or unrestricted resources to make certain payments, on a case by case basis, when both restricted and unrestricted assets are available for the same purposes.

(o) *Intragovernmental Charges*

Certain functions of the Municipality of a general and administrative nature are centralized and the related costs are allocated to the various funds of the Municipality, including the Utility. Such costs allocated to the Utility totaled $4,214,954 and $3,580,714 for the years ended December 31, 2018 and 2017, respectively, including general liability and workers compensation of $660,414 for 2018 and $504,452 for 2017.

(p) *Utility Revenue Distribution/Municipal Service Assessment (MUSA)*

Prior to 2006, the RCA restricted the Utility from making a revenue distribution or paying the gross receipts portion of the MUSA. That restriction was removed in December 2005. The Utility made an annual revenue distribution to the Municipality for the years 2006 - 2015, which by Ordinance, was up to a maximum of 5% of the Utility's gross revenues, excluding restricted revenues. During those years the Utility also included the gross receipts portion, considered supplemental MUSA, at 1.25% times the actual gross operating revenues in its payment of MUSA. During 2017, the Municipality eliminated the gross receipts portion of the MUSA and revised the methodology for calculating the Utility Revenue Distribution.

Beginning January 1, 2016, the Utility is restricted by the RCA from making revenue distributions to the Municipality, with the exception of MUSA. The Utility's distribution for MUSA in 2018 and 2017 was $9,565,771 and $9,331,662, respectively.

(q) *Environmental*

The Utility has adopted an aggressive policy designed to identify and mitigate the potential effects of past, present, and future operational activities that may result in environmental impact. It is the Utility's accounting policy to record a liability when the likelihood of responsibility for an environmental impact is probable and the cost of mitigating the impact is estimable within reasonable limits. Such costs are capitalized if they result in an extension of the assets' life, increase the capacity, or improve the safety or efficiency of property owned by the Utility; or mitigate or prevent environmental contamination that has yet to occur and that otherwise may result from future operations or activities. At December 31, 2016, the Utility recorded a liability of $760,000 for environmental cleanup responsibilities related to a capital project at Hank Nikkels Power Plant 1. At December 31, 2018 and 2017, the liability balance was $0.00 and $511,787, respectively. See Note 8(a). There were no other environmental issues that met the Utility's accounting policy and accordingly, no provision has been made in the accompanying financial statements for any potential liability.

(r) *Net Pension Liability*

For purposes of measuring net pension liability, deferred outflows and inflows of resources related to pensions and pension expenses, information about the fiduciary net position of the Public Employees' Retirement System (PERS) and additions to/from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Details regarding the net pension liability are discussed in Note 7.

(s) Net Other Postemployment Benefits (OPEB) Liability

For purposes of measuring net OPEB liability, deferred outflows and inflows of resources related to OPEB and OPEB expenses, information about the fiduciary net position of PERS and additions to/from PERS' fiduciary net position have been determined on the same basis as they are reported by PERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value. Details regarding the net OPEB liability are discussed in Note 7.

(t) Reclassifications

Certain amounts previously reported may have been reclassified to conform to current presentations. The reclassifications had no effect on the previously reported change in net position.

(2) Change in Accounting Principle

As discussed in Note 7 to the financial statements, the Utility participates in the PERS plans. In 2018, the Utility adopted the provisions of GASB Statement No. 75 *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, which, among other accounting and reporting criteria, requires the Utility to recognize its proportional share of the net OPEB liability (and related deferred inflows and outflows of resources), as of the beginning of the Utility's fiscal year. The prior period presented in the financial statements was not restated as it was not practical to do. As a result of the implementation of this statement, the Utility has recorded an opening balance adjustment to reflect opening balance OPEB liabilities and related accounts and to decrease opening net position as follows:

Opening net position as originally presented	Change in accounting principle adjustment	Opening net position, as restated after change in accounting principle
$ 269,457,246	$ (2,525,319)	$ 266,931,927

(3) Cash and Investments

At December 31, 2018 and 2017, the Municipality had cash and investments in a general cash pool (Central Treasury). The Utility also carries certain balances for the Utility, beginning in 2017, in separate accounts for Interim Rate Increase Escrow and Asset Retirement Obligations. Fixed income maturities for these accounts are as follows:

December 31, 2018

		Fixed Income Investment Maturities (in years)			
Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
Utility share of petty cash	$ 1,000				
Municipal Central Treasury - Unrestricted					
Cash & Money Market Funds	$ 21,308,292	$ -	$ -	$ -	$ -
Repurchase Agreements	22,398,105	22,398,105	-	-	-
U.S. Treasuries	148,917,831	80,567,294	55,484,846	12,414,634	451,057
U.S. Agencies	20,351,315	10,114	10,552,227	5,456,530	4,332,444
Asset-Backed Securities**	25,781,328	394,826	17,416,412	2,667,894	5,302,196
Corporate Securities	136,435,070	40,724,193	55,624,808	38,378,958	1,707,111
Payables					
	$ 375,191,941	$ 144,094,532	$ 139,078,293	$ 58,918,016	$ 11,792,808
Municipal Central Treasury - Restricted					
Cash & Money Market Funds	$ 22,072,465	$ -	$ -	$ -	$ -
Repurchase Agreements	3,164,717	3,164,717	-	-	-
U.S. Treasuries	34,914,468	11,383,671	21,712,952	1,754,113	63,732
U.S. Agencies	21,222,562	1,429	19,838,011	770,974	612,148
Asset-Backed Securities**	3,642,746	55,787	2,460,834	376,957	749,168
Corporate Fixed Income Securities	19,277,450	5,754,082	7,859,449	5,422,715	241,204
Payables					
	$ 104,294,408	$ 20,359,686	$ 51,871,246	$ 8,324,759	$ 1,666,252
Utility share of Municipal central treasury	**$ 117,878,524**				

* Market value plus accrued income.

** Includes asset-backed securities, residential and commercial mortgage-backed securities, and collateralized debt obligations.

December 31, 2018, continued:

		Fixed Income Investment Maturities (in years), continued			
Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
Asset Retirement Obligation Fund					
Cash & Money Market Funds	$ 85,668	$ -	$ -	$ -	$ -
U.S. Fixed Income	9,111,756	606,183	2,345,204	2,642,503	3,517,866
U.S. TIPS	1,360,928	-	1,360,928	-	-
U.S. Large-Cap Equity	1,837,725	-	-	-	-
U.S. Mid-Cap Equity	114,581	-	-	-	-
U.S. Small-Cap Equity	108,832	-	-	-	-
International Developed Equity	524,196	-	-	-	-
Emerging Markets Equity	129,663	-	-	-	-
Real Estate	642,504	-	-	-	-
	$ 13,915,853	$ 606,183	$ 3,706,132	$ 2,642,503	$ 3,517,866
Total Utility	**$ 131,795,377**				

December 31, 2017

		Fixed Income Investment Maturities (in years)			
Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
Utility share of petty cash	**$ 1,000**				
Interim Rate Increase Escrow Money Market	**27,250,254**				
Municipal Central Treasury - Restricted					
Cash & Money Market Funds	$ 32,165,339	$ -	$ -	$ -	$ -
Commercial Paper	99,654	99,654	-	-	-
U.S. Treasuries	22,840,772	15,819,079	5,646,873	1,374,820	-
U.S. Agencies	21,909,848	4,118,857	16,986,967	453,090	350,934
Asset-Backed Securities**	2,253,879	-	1,445,012	289,464	519,313
Corporate Fixed Income Securities	7,920,460	932,735	3,878,616	2,831,105	278,004
	$ 87,189,952	$ 20,970,325	$ 27,957,468	$ 4,948,479	$ 1,148,251
Municipal Central Treasury - Unrestricted					
Cash & Money Market Funds	$ 37,673,284	$ -	$ -	$ -	$ -
Commercial Paper	1,535,603	1,535,603	-	-	-
U.S. Treasuries	121,706,339	13,506,923	87,014,400	21,185,016	-
U.S. Agencies	13,180,799	550,253	241,092	6,981,798	5,407,656
Asset-Backed Securities**	34,730,718	-	22,268,024	4,460,439	8,002,255
Corporate Securities	122,048,793	14,372,805	59,766,782	43,625,370	4,283,836
	$ 330,875,536	$ 29,965,584	$ 169,290,298	$ 76,252,623	$ 17,693,747
	$ 418,065,488	$ 50,935,909	$ 197,247,766	$ 81,201,102	$ 18,841,998
Utility share of municipal central treasury	**$ 100,968,384**				

* Market value plus accrued income.
** Includes asset-backed securities, residential and commercial mortgage-backed securities, and collateralized debt obligations.

December 31, 2017, continued

Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
	Fixed Income Investment Maturities (in years), continued				
Asset Retirement Obligation Fund					
Cash & Money Market Funds	$ 456,333	$ -	$ -	$ -	$ -
U.S. Fixed Income	8,220,807	-	2,352,657	3,622,444	2,245,706
U.S. TIPS	942,226	-	942,226	-	-
U.S. Large-Cap Equity	1,751,027	-	-	-	-
U.S. Mid-Cap Equity	265,692	-	-	-	-
U.S. Small-Cap Equity	261,154	-	-	-	-
International Developed Equity	657,596	-	-	-	-
Emerging Markets Equity	133,715	-	-	-	-
Real Estate	510,327	-	-	-	-
	$ 13,198,877	$ -	$ 3,294,883	$ 3,622,444	$ 2,245,706
Total Utility	**$ 141,418,515**				

Reported in the Statement of Net Position:

	2018	2017
Restricted assets:		
Customer deposits	$ 1,225,452	1,186,226
Interim rate escrow investment	-	27,250,254
Debt service investment	2,058,443	2,098,515
Revenue bond reserve investments	23,718,574	23,335,229
Revenue bond operations and maintenance investment	15,206,000	14,235,000
Future natural gas purchases investment	5,732,181	3,811,326
Future BRU construction or natural gas purchases investment	8,032,509	23,711,907
Asset retirement obligation sinking fund investment	13,915,853	13,198,877
Total restricted assets	$ 69,889,012	108,827,334
Unrestricted equity in general cash pool, including petty cash	61,906,365	32,591,181
Total Utility cash and investments	$ 131,795,377	141,418,515

(a) Municipal Central Treasury

The Municipality manages its Central Treasury in four portfolios; one internally managed portfolio and three externally managed duration portfolios based on liability duration and cash needs: working capital, contingency reserve and strategic reserve.

The Municipality maintains a comprehensive policy over cash and investments that is designed to mitigate risks while maximizing investment return and providing for operating liquidity. Pursuant to Anchorage Municipal Code (AMC) 6.50.030, the Municipality requires investments to meet specific rating and issuer requirements.

Both externally and internally managed investments are subject to the primary investment objectives outlined in AMC 6.50.030, in priority order as follows: safety of principal, liquidity, return on investment and duration matching. Consistent with these objectives, AMC 6.50.030 authorizes investments that meet the following rating and issuer requirements:

- Obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government sponsored corporations and agencies.

- Corporate debt securities that are guaranteed by the U.S. government or the Federal Deposit Insurance Corporation (FDIC) as to principal and interest.

- Taxable and tax-exempt municipal securities having a long-term rating of at least A- by a nationally recognized rating agency or taxable or tax-exempt municipal securities having a short-term rating of at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch.

- Debt securities issued and guaranteed by the International Bank for Reconstruction and Development (IBRD) and rated AAA by a nationally recognized rating agency.

- Commercial paper, excluding asset-backed commercial paper, rated at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch.

- Bank debt obligations, including unsecured certificates of deposit, notes, time deposits, and bankers' acceptances (with maturities of not more than 365 days), and deposits with any bank, the short-term obligations of which are rated at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch and which is either:

    a) Incorporated under the laws of the United States of America, or any state thereof, and subject to supervision and examination by federal or state banking authorities; or
    b) Issued through a foreign bank with a branch or agency licensed under the laws of the United States of America, or any state thereof, or under the laws of a country with a Standard & Poor's sovereign rating of AAA, or a Moody's sovereign rating for bank deposits of Aaa, or a Fitch national rating of AAA, and subject to supervision and examination by federal or state banking authorities.

- Repurchase agreements secured by obligations of the U.S. government, U.S. agencies, or U.S. government-sponsored corporations and agencies.

- Dollar denominated corporate debt instruments rated BBB- or better (investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Dollar denominated corporate debt instruments rated lower than BBB- (non-investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency, including emerging markets.

- Dollar denominated debt instruments of foreign governments rated BBB- or better (investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Asset Backed Securities (ABS), excluding commercial paper, collateralized by: credit cards, automobile loans, leases and other receivables which must have a credit rating of AA- or above by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Mortgage Backed Securities, including generic mortgage-backed pass-through securities issued by Ginnie Mae, Freddie Mac, and Fannie Mae, as well as non-agency mortgage-backed securities, Collateralized Mortgage Obligations (CMOs), or Commercial Mortgage-Backed Securities (CMBS), which must have a credit rating of AA- or better by Standard & Poor's or the equivalent by another nationally recognized rating agency.

- Debt issued by the Tennessee Valley Authority

- Money Market Mutual Funds rated Am or better by Standard & Poor's, or the equivalent by another nationally recognized rating agency, as long as they consist of allowable securities as outlined above.

- The Alaska Municipal League Investment Pool (AMLIP).

- Mutual Funds consisting of allowable securities as outlined above.

- Interfund Loans from a Municipal Cash Pool to a Municipal Fund.

In addition to providing a list of authorized investments, AMC 06.50.030 specifically prohibits investment in the following:

- Structured Investment Vehicles.

- Asset Backed Commercial Paper.

- Short Sales.

- Securities not denominated in U.S. Dollars.

- Commodities.

- Real Estate Investments.

- Derivatives, except "to be announced" forward mortgage-backed securities (TBAs) and derivatives for which payment is guaranteed by the U.S. government or an agency thereof.

The Investment Management Agreement (IMA) for each external manager and the policy and procedures (P&P) applicable to the internally managed investments provide additional guidelines for each portfolio's investment mandate. The IMA and P&P limit the concentration of investments for the working capital portfolio at the time new investments are purchased as follows for 2018:

Investment Type	Concentration Limit	Working Capital Portfolio Holding % at December 31, 2018
U.S. Government Securities*	50% to 100% of investment portfolio	53%
Repurchase Agreements	0% to 50% of investment portfolio	13%
Certificates of Deposit	0% to 25% of investment portfolio Maximum 5% per issuer	0%
Commercial Paper	0% to 25% of investment portfolio Maximum 5% per issuer	0%
Bankers Acceptances	0% to 25% of investment portfolio Maximum 5% per issuer	0%
Corporate Fixed Income**	0% to 25% of investment portfolio Maximum 5% per issuer	18%
Taxable & tax-exempt municipal debt securities	0% to 15% of investment portfolio Maximum 5% per issuer	0%
Dollar denominated debt of foreign governments and the International Bank for Reconstruction and Development (IBRD)	0% to 10% of investment portfolio Maximum 5% per issuer	0%
Money Market Mutual Funds***	0% to 25% of investment portfolio	16%
		100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.
**The maximum exposure to Corporate floating and variable rate debt securities in the Working Capital Portfolio is 10 percent. Corporate Fixed Income Debt Securities must have a final maturity within one (1) year of purchase, and Corporate Floating Rate or Variable Rate Debt Securitites must have a final maturity witin two (2) years of purchase
***The Working Capital portfolio may not be invested in AMLIP.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Notes to Financial Statements

December 31, 2018 and 2017

The IMA and P&P limit the concentration of investments for the internally managed portfolio at the time new investments are purchased as follows for 2018:

Investment Type	Concentration Limit	Internally Managed Holding % at December 31, 2018
U.S. Government Securities*	50% to 100% of investment portfolio	71%
Repurchase Agreements	0% to 50% of investment portfolio	0%
Certificates of Deposit	0% to 50% of investment portfolio	0%
Bankers Acceptances	0% to 25% of investment portfolio Maximum 5% per issuer	0%
Commercial Paper	0% to 25% of investment portfolio Maximum 5% per issuer	0%
Corporate Fixed Income	0% to 25% of investment portfolio Maximum 5% per issuer	0%
Alaska Municipal League Investment Pool (AMLIP)	0% to 25% of investment portfolio	
Money Market Mutual Funds**	0% to 25% of investment portfolio	29%
Dollar Denominated Fixed Income Securities, other than those listed herein, rated by at least one nationally recognized rating agency	0% to 15% of investment portfolio Maximum 5% per issuer	0%
		100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.
**The Internally Managed Portfolio contained an excess of cash equivalents at December 31, 2018 in anticipation of planned spending within a week. The portfolio was back in compliance the first week of 2019.

The IMA and P&P limit the concentration of investments for the working capital portfolio and the internally managed portfolio at the time new investments are purchased as follows for 2017:

Investment Type	Concentration Limit	Working Capital Portfolio Holding % at December 31, 2017	Internally Managed Holding % at December 31, 2017
U.S. Government Securities*	50% to 100% of investment portfolio	28%	55%
Repurchase Agreements	0% to 50% of investment portfolio	0%	0%
Certificates of Deposit	0% to 25% of investment portfolio Maximum 5% per issuer	0%	0%
Bankers Acceptances	0% to 25% of investment portfolio Maximum 5% per issuer	0%	0%
Commercial Paper	0% to 25% of investment portfolio Maximum 5% per issuer	2%	0%
Corporate Fixed Income**	0% to 25% of investment portfolio Maximum 5% per issuer	11%	0%
Alaska Municipal League Investment Pool (AMLIP)***	0% to 25% of investment portfolio	0%	0%
Money Market Mutual Funds****	0% to 25% of investment portfolio	59%	45%
Dollar Denominated Fixed Income Securities, other than those listed herein, rated by at least one nationally recognized rating agency	0% to 15% of investment portfolio Maximum 5% per issuer	0%	0%
		100%	100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.
**The maximum exposure to Corporate floating and variable rate debt securities in the Working Capital Portfolio is 10 percent.
***The Working Capital portfolio may not be invested in AMLIP.
****The Working Capital and Internally Managed Portfolio contained an excess of cash equivalents at December 31, 2017 in anticipation of planned spending within a week. The portfolios were back in compliance the first week of 2018.

(b) Beluga River Asset Retirement Obligation Fund

Funds set aside to pay for dismantling, removing, and restoring assets of the Beluga River Unit gas field were transferred from the MOA Central Treasury to a separate investment portfolio in 2017, per assembly ordinance.

The Beluga River Asset Retirement Obligation Fund is managed to maximize capital appreciation with a long-term rate of return. The Fund is authorized to invest in the following assets:

- Domestic equities and International equities, including real estate investment trusts.
- Investment grade dollar-denominated fixed income securities.
- Cash and money market instruments.

The Beluga River Asset Retirement Obligation Fund limits the concentration of its investments as follows:

December 31, 2018

Investment Type	Lower Limit	Upper Limit	Target	Investment Holding % at December 31, 2018
Domestic Equities:				
Large Cap	5%	20%	13%	13%
Mid Cap	0%	5%	1%	1%
Small Cap	0%	5%	1%	1%
International Equities:				
Developed	0%	10%	4%	4%
Emerging Markets	0%	5%	1%	1%
Real Estate:				
Real Estate Funds	1%	10%	5%	4%
Fixed Income:				
Domestic Fixed Income	55%	75%	65%	65%
TIPS	5%	15%	10%	10%
Cash & Cash Equivalents:				
Cash Equivalents	0%	15%	0%	1%
				100%

December 31, 2017

Investment Type	Lower Limit	Upper Limit	Target	Investment Holding % at December 31,
Domestic Equities:				
Large Cap	5%	20%	13%	13%
Mid Cap	0%	5%	1%	2%
Small Cap	0%	5%	1%	2%
International Equities:				
Developed	0%	10%	4%	5%
Emerging Markets	0%	5%	1%	1%
Real Estate:				
Real Estate Funds	0%	10%	5%	4%
Fixed Income:				
Domestic Fixed Income	55%	75%	65%	62%
TIPS	5%	15%	10%	7%
Cash & Cash Equivalents:				
Cash Equivalents	0%	15%	0%	4%
				100%

(c) *Interest Rate Risk*

Interest rate risk is the risk that changes in interest rates will adversely affect the fair value of an investment. The externally managed portfolios of the Municipal Central Treasury utilize the duration method to measure exposure to interest rate risk.

Duration is a measure of an investment's sensitivity to interest rate changes, and represents the sensitivity of an investment's market price to a one percent change in interest rates. The effective duration of an investment is determined by its expected future cash flows, factoring in uncertainties introduced through options, prepayments, and variable rates. The effective duration of a pool is the average fair value weighted effective duration of each security in the pool.

AMC 6.50.030 requires the Working Capital Portfolio have a duration of zero to 270 days. At December 31, 2018, the Working Capital Portfolio had a duration of 1.37 years, or approximately 500 days, and was not within the targeted duration. At December 31, 2017, the Working Capital Portfolio had a duration of 0.14 years, or approximately 51 days. AMC 6.50.030 also requires that the Contingency Reserve Portfolio have an average duration within half a year of its benchmark. At December 31, 2018, the Contingency Reserve Portfolio had a duration of 1.83 years as compared to its benchmark, Barclays 1-3 Year Government Index, which had a duration of 1.90 years. At December 31, 2017, the Contingency Reserve Portfolio had a duration of 1.94 years as compared to its benchmark, Barclays 1-3 Year Government Index, which had a duration of 1.91 years. AMC 6.50.030 requires the Strategic Reserve Portfolio have a maximum duration no greater than one year in excess of its benchmark. At December 31, 2018, the Strategic Reserve Portfolio had a duration of 3.12 years as compared to its benchmark, Barclays Intermediate Government/Corporate Index, which had a duration of 2.91 years. At December 31, 2017, the Strategic Reserve Portfolio had a duration of 3.70 years as compared to its benchmark, Barclays Intermediate Government/Corporate Index, which had a duration of 3.73 years.

The effective duration of the externally managed portfolio of the Municipal Central Treasury working capital portfolio at December 31, 2018, was 1.37 years, which is not within the targeted duration of +/-.25 years of the Merrill Lynch 90-day Treasury Bill Index, as required per Alaska Permanent Capital Management Investment Manager Agreement. The effective duration of the contingency reserve and strategic reserve portfolios at December 31, 2018, were 1.83 years, and 3.12 years, respectively, which are within the required durations per the policy.

The effective durations of the externally managed portfolios of the Municipal Central Treasury (working capital, contingency reserve and strategic reserve) at December 31, 2017, were 0.14 years, 1.94 years, and 3.70 years, respectively, which are within the required durations per the policy

The Beluga River Asset Retirement Obligation Fund does not have Investment Policies addressing interest rate risk.

(d) Credit Risk

Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. For fixed income securities, this risk is generally expressed as a credit rating.

At December 31, 2018, the Municipal Central Treasury's investment in marketable debt securities, excluding U.S. Treasury and Agency securities, totaled $185,136,594. The distribution of ratings on these securities was as follows:

Moody's		S&P	
Aaa	13%	AAA	11%
Aa	11%	AA	6%
A	22%	A	25%
Baa	26%	BBB	30%
Ba or Lower	24%	BB or Lower	22%
Not Rated	4%	Not Rated	6%
	100%		100%

At December 31, 2017, the Municipal Central Treasury's investment in marketable debt securities, excluding U.S. Treasury and Agency securities, totaled $167,959,335. The distribution of ratings on these securities was as follows:

Moody's		S&P	
Aaa	17%	AAA	16%
Aa	4%	AA	2%
A	21%	A	20%
Baa	23%	BBB	27%
Ba or Lower	32%	BB or Lower	30%
Not Rated	3%	Not Rated	5%
	100%		100%

At December 31, 2018 and 2017, the Beluga River Asset Retirement Obligation Fund investment in fixed income securities, including U.S. TIPS, totaled $10,472,684 and $9,163,033, respectively. The distribution of ratings on these securities was as follows:

2018

Moody's	
Aaa	53%
Aa	1%
A	14%
Baa	9%
Not Rated	23%
	100%

2017

Moody's	
Aaa	75%
Aa	3%
A	14%
Bbb	8%
	100%

(e) Concentration of Credit Risk

Concentration of credit risk is the risk of loss attributed to the magnitude of an entity's investment in a single issuer. GASB Statement No. 40 requires disclosure when the amount invested in a single issuer exceeds 5 percent or more of total investments. Investments issued or explicitly guaranteed by the U.S. Government, as well as mutual funds and other pooled investments, are exempted from this requirement.

At December 31, 2018 and 2017, the Municipal Central Treasury and the Beluga River Asset Retirement Obligation Fund, had no investments in any single issuer exceeding 5 percent of total investments.

(f) Custodial Credit Risk

Custodial credit risk is the risk, in event of the failure of a depository institution, that an entity will not be able to recover deposits or collateral securities in the possession of an outside party. For investments, custodial credit risk is the risk, in event of the failure of the counterparty to a transaction, that an entity will not be able to recover the value of the investment or collateral securities in the possession of an outside party. All collateral consists of obligations issued, or fully insured or guaranteed as to payment of principal and interest, by the United States of America, an agency thereof or a United States government sponsored corporation, with market value not less than the collateralized deposit balances.

AMC 6.50.030 requires that repurchase agreements be secured by obligations of the U.S. government, U.S. agencies, or U.S. government-sponsored corporations and agencies. As of December 31, 2018 and 2017 cash deposits and investments were not exposed to custodial credit risk.

(g) Foreign Currency Risk

Foreign currency risk is the risk that changes in exchange rates will adversely impact the fair value of an investment. The Municipality has no specific policy addressing foreign currency risk; however foreign currency risk is managed through the requirements of AMC 6.50.030 and the asset allocation policies of each portfolio.

The Municipal Central Treasury is not exposed to foreign currency risk because AMC 6.50.030 explicitly prohibits the purchase of securities not denominated in U.S. Dollars. At December 31, 2018 and 2017, all debt obligations held in the Municipal Central Treasury were payable in U.S. Dollars.

(h) *Fair Value Measurements*

At December 31, 2018 and 2017, the Municipality had the following cash and investments, valued as follows:

- Asset-backed securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Short-term collective investments such as money market funds are valued at amortized cost.
- Commercial paper is valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Corporate securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Domestic equity funds are valued at the closing price reported on the active market on which the individual funds traded.
- Real estate funds are valued at the closing price reported on the active market on which the individual funds are traded.
- International equity funds are valued at the closing price reported on the active market on which the individual funds traded.
- Repurchase agreements are valued at the daily closing price as reported using the daily price quoted by the financial institution holding the investment for the Municipality.
- U.S Treasuries are valued at the closing price reported on the active market on which the individual securities traded.
- U.S Agencies are valued using pricing models maximizing the use of observable inputs for similar securities.
- U.S TIPs are valued at the closing price reported on the active market on which the individual securities traded.

The Municipality utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Municipality determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: quoted prices for identical assets or liabilities in active markets
- Level 2 Inputs: quoted prices for similar assets or liabilities in active or inactive markets; or inputs other than quoted prices that are observable
- Level 3 Inputs: significant unobservable inputs for assets or liabilities

The Municipality categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Municipality as a whole has the following recurring fair value measurements as of December 31, 2018 and 2017:

December 31, 2018:

		Fair Value Measurements Using	
Investment Type:	December 31, 2018	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
Central Treasury - Restricted			
Investments Measured at Fair Value			
U.S. Treasuries	$ 34,914,468	$ 28,487,275	$ 6,427,192
U.S. Agencies	21,222,562	-	21,222,562
Asset-Backed Securities	3,642,746	-	3,642,746
Corporate Securities	19,277,450	-	19,277,450
	79,057,226	28,487,275	50,569,950
Investments Measured at Amortized Cost			
Money Market Funds	22,072,465		
Repurchase Agreements	3,164,717		
Total Central Treasury - Restricted	$ 104,294,408		

December 31, 2018, continued

Investment Type:	December 31, 2018	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
Central Treasury- Unrestricted			
Investments Measured at Fair Value			
U.S. Treasuries	$ 148,917,831	$ 103,429,738	$ 45,488,093
U.S. Agencies	20,351,315	-	20,351,315
Asset-backed Securities	25,781,328	-	25,781,328
Corporate Securities	136,435,070	-	136,435,070
	331,485,544	103,429,738	228,055,806
Investments Measured at Amortized Cost			
Money Market Funds	21,308,292		
Repurchase Agreements	22,398,105		
Total Central Treasury- Unrestricted	$ 375,191,941		
Beluga River Asset Retirement Obligation Fund			
Investments Measured at Fair Value			
U.S. Fixed Income	$ 9,111,756	$ -	$ 9,111,756
U.S. TIPS	1,360,928	1,360,928	-
U.S. Large-Cap Equity	1,837,725	1,837,725	-
U.S. Mid-Cap Equity	114,581	114,581	-
U.S. Small-Cap Equity	108,832	108,832	-
International Developed Equity	524,196	524,196	-
Emerging Markets Equity	129,663	129,663	-
Real Estate	642,504	642,504	-
	13,830,185	4,718,429	9,111,756
Money Market Funds	85,668		
Total Asset Retirement Obligation Fund	$ 13,915,853		

December 31, 2017

Investment Type:	December 31, 2017	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Fair Value Measurements Using: Significant Other Observable Inputs (Level 2)
Central Treasury - Restricted			
Investments Measured at Fair Value			
Commercial Paper	$ 99,654	$ -	$ 99,654
U.S. Treasuries	22,840,772	22,840,772	-
U.S. Agencies	21,909,848	-	21,909,848
Asset-Backed Securities	2,253,879	-	2,253,879
Corporate Securities	7,920,460	-	7,920,459
	$ 55,024,613	$ 22,840,772	$ 32,183,840
Investments Measured at Amortized Cost			
Cash & Money Market Funds	32,165,339		
Total Central Treasury - Restricted	$ 87,189,952		
Central Treasury - Unrestricted			
Investments Measured at Fair Value			
Commercial Paper	$ 1,535,603	$ -	$ 1,535,603
U.S. Treasuries	121,706,339	121,706,339	-
U.S. Agencies	13,180,799	-	13,180,799
Asset-Backed Securities	34,730,718	-	34,730,718
Corporate Securities	122,048,793	-	122,048,793
	$ 293,202,252	$ 121,706,339	$ 171,495,913
Investments Measured at Amortized Cost			
Money Market Funds	37,673,284		
	37,673,284		
Total Central Treasury- Unrestricted	$ 330,875,536		

December 31, 2017, continued

Investment Type:	December 31, 2017	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Fair Value Measurements Using: Significant Other Observable Inputs (Level 2)
Asset Retirement Obligation Fund			
Investments Measured at Fair Value			
U.S. Fixed Income	$ 8,220,807	$ 3,818,364	$ 4,402,443
U.S. TIPS	942,226	942,226	-
U.S. Large-Cap Equity	1,751,027	1,751,027	-
U.S. Mid-Cap Equity	265,692	265,692	-
U.S. Small-Cap Equity	261,154	261,154	-
International Developed Equity	657,596	657,596	-
Emerging Markets Equity	133,715	133,715	-
Real Estate	510,327	510,327	-
	$ 12,742,544	$ 8,340,101	$ 4,402,443
Investments Measured at Amortized Cost			
Money Market Funds	456,333		
Total Asset Retirement Obligation Fund	$ 13,198,877		
Interim Rate Increase Escrow Money Market			
Investments Measured at Amortized Cost			
Money Market Funds	$ 27,250,254		

(4) Capital Assets

A summary of capital assets at December 31, 2018 follows:

	January 1, 2018	Additions	Deductions	December 31, 2018
Electric plant in service	$ 975,077,993	$ 30,377,787	$ (7,373,577)	$ 998,082,203
Less accumulated depreciation	261,683,609	31,937,280	(10,249,246)	283,371,643
Net electric plant in service	713,394,384	(1,559,493)	2,875,669	714,710,560
Natural gas production and gathering plant	345,231,780	1,222,997	-	346,454,777
Less accumulated depletion	194,387,360	7,094,304	-	201,481,664
Net gas plant in service	150,844,420	(5,871,307)	-	144,973,113
Net electric and gas plant in service	864,238,804	(7,430,800)	2,875,669	859,683,673
Intangible plant, less accumulated amortization of $12,767,052 in 2018 and $12,661,781 in 2017	2,610,447	-	(105,272)	2,505,175
Construction work in progress	22,957,440	23,162,877	(31,218,032)	14,902,285
Total capital assets	$ 889,806,691	$ 15,732,077	$ (28,447,635)	$ 877,091,133

Included in the Construction Work in progress are retirement assets as follows:

	$ 768,992	$ 1,097,142	$ (840,247)	$ 1,025,887

In accordance with the requirements of FERC, disposals of retirement assets are not placed in service, rather they are reported as deductions from accumulated depreciation.

A summary of capital assets at December 31, 2017 follows:

	January 1, 2017	Additions	Deductions	December 31, 2017
Electric plant in service	$ 948,075,842	$ 28,786,514	$ (1,784,363)	$ 975,077,993
Less accumulated depreciation	232,593,710	30,819,404	(1,729,505)	261,683,609
Net electric plant in service	715,482,132	(2,032,890)	(54,858)	713,394,384
Natural gas production and gathering plant	345,231,780	-	-	345,231,780
Less accumulated depletion	182,975,820	11,418,229	(6,689)	194,387,360
Net gas plant in service	162,255,960	(11,418,229)	6,689	150,844,420
Net electric and gas plant in service	877,738,092	(13,451,119)	(48,169)	864,238,804
Intangible plant, less accumulated amortization of $12,661,781 in 2017 and $12,556,509 in 2016	2,715,719	-	(105,272)	2,610,447
Construction work in progress	15,783,204	30,071,559	(22,897,323)	22,957,440
Total capital assets	$ 896,237,015	$ 16,620,440	$ (23,050,764)	$ 889,806,691

Included in the Construction Work in progress are retirement assets as follows:

	$ 185,544	$ 648,612	$ (65,164)	$ 768,992

In accordance with the requirements of FERC, disposals of retirement assets are not placed in service, rather they are reported as deductions from accumulated depreciation.

(5) Long-Term Liabilities

(a) Revenue Bonds Payable

A summary of revenue bonds payable consist of the following at December 31:

		2018	2017
Revenue bonds:			
2005 Series A, effective interest rate at 4.993858% due 2026	$	12,150,000	17,565,000
2009 Series A, effective interest rate at 5.009% due 2039		15,240,000	15,240,000
2009 Series B, effective interest rate at 5.009% due 2039 taxable		114,760,000	114,760,000
2014 Series A, effective interest rate at 3.81% due 2044		173,355,000	175,805,000
		315,505,000	323,370,000
Unamortized discount		(446,018)	(476,692)
Unamortized premium		17,436,399	18,721,619
	$	332,495,381	341,614,927

Debt service requirements to maturity at December 31, 2018 are as follows:

	Senior Lien Electric Revenue Bonds		
	Principal	Interest	Total
2019	$ 7,730,000	$ 16,950,747	$ 24,680,747
2020	8,075,000	16,603,147	24,678,147
2021	8,410,000	16,268,347	24,678,347
2022	8,760,000	15,917,897	24,677,897
2023	9,200,000	15,479,897	24,679,897
2024 - 2028	52,945,000	69,842,811	122,787,811
2029 - 2033	66,445,000	53,284,957	119,729,957
2034 - 2038	83,515,000	31,911,123	115,426,123
2039 - 2043	59,285,000	9,541,003	68,826,003
2044	11,140,000	445,600	11,585,600
Senior lien revenue bonds payable	$ 315,505,000	$ 246,245,529	$ 561,750,529

The Utility's revenue bonds bear interest at effective rates of 3.75% to 6.5% and require the establishment of reserves over a five-year period at least equal to the maximum annual debt service on all outstanding senior lien bonds. The senior lien revenue bond covenants further stipulate that net revenue before depreciation and amortization for each year will be equal to at least 1.35 times the debt service requirements for that year. At December 31, 2018 and 2017, the Utility had satisfied the reserve requirements and debt service covenants. The Utility has pledged future customer revenues, net of specified operating expenses, to repay revenue bonds. Proceeds from the bonds provided financing for construction and other capital improvements. The bonds are payable solely from customer net revenues and are payable through 2044. The total principal remaining to be paid on the bonds for the years ended December 31, 2018 and 2017 was $315,505,000 and $323,370,000, respectively. Principal and interest paid for the years ended December 31, 2018 and 2017 were $25,178,097 and $25,179,497, respectively. Total customer net revenues for the years ended December 31, 2018 and 2017 were $59,871,466 and $67,680,056, respectively.

(c) ***Notes Payable***

In February 2012, the Assembly authorized the issuance of commercial paper in one or more series in the aggregate principal amount not to exceed three hundred million dollars ($300,000,000).

In April 2015, the Utility redeemed all outstanding commercial paper and entered into a short-term borrowing agreement with Wells Fargo Municipal Capital Strategies, LLC, herein referred to as the Direct Drawdown Purchase Program (DDPP). This borrowing program continued to fulfill the purpose of the Commercial Paper program, but at a lower aggregate fee and interest cost to the Utility over the life of the program. The DDPP was used by the Utility to complete construction of Generation Plant 2A. At December 31, 2016 the outstanding balance of DDPP notes payable was $181,000,000. During 2017, $10,900,000 was drawn down for completion of Generation Plant 2A. On November 30, 2017 the loan term was extended to November 29, 2019. No further drawdowns are anticipated. The Utility intends to extend the loan under the same terms until December 31, 2020.

At December 31, 2018 and 2017 the balance was $191,900,000. The notes are reflected as long-term notes payable on the Utility's Statement of Net Position, as the principal is not expected to be paid within one year.

The following is a summary of long-term liability activity as of December 31, 2018 and 2017:

	Balance January 1, 2018 *	Additions	Reductions	Balance December 31, 2018	Due within one year
Revenue bonds payable:					
Series 2005A	$ 17,565,000	$ -	$ 5,415,000	$ 12,150,000	$ 1,280,000
Series 2009A	15,240,000	-	-	15,240,000	2,560,000
Series 2009B	114,760,000	-	-	114,760,000	-
Series 2014A	175,805,000	-	2,450,000	173,355,000	3,890,000
Senior electric revenue bonds	323,370,000	-	7,865,000	315,505,000	7,730,000
Unamortized premiums/discounts	18,244,927	-	1,254,546	16,990,381	-
Total revenue bonds payable	341,614,927	-	9,119,546	332,495,381	7,730,000
Notes payable	191,900,000	-	-	191,900,000	-
Compensated absences payable	2,812,140	1,622,046	1,907,763	2,526,423	2,526,423
Net pension liability	12,270,893	-	909,157	11,361,736	-
Net OPEB Liability	1,839,038 *	489,294	-	2,328,332	-
Asset retirement obligation	15,823,732	719,980	-	16,543,712	-
Total long term liabilities	$ 566,260,730	$ 2,831,320	$ 11,936,466	$ 557,155,584	$ 10,256,423

* Per implementation of GASB Statement No. 75, the Utility restated beginning balances for net OPEB Liability.

	Balance January 1, 2017	Additions	Reductions	Balance December 31, 2017	Due within one year
Revenue bonds payable:					
Series 2005A	$ 22,705,000	$ -	$ 5,140,000	$ 17,565,000	$ 5,415,000
Series 2009A	15,240,000	-	-	15,240,000	-
Series 2009B	114,760,000	-	-	114,760,000	-
Series 2014A	178,185,000	-	2,380,000	175,805,000	2,450,000
Senior electric revenue bonds	330,890,000	-	7,520,000	323,370,000	7,865,000
Unamortized premiums/discounts	19,596,890	-	1,351,963	18,244,927	-
Total revenue bonds payable	350,486,890	-	8,871,963	341,614,927	7,865,000
Notes payable [r]	-	191,900,000	-	191,900,000	-
Compensated absences payable	2,974,329	2,178,541	2,340,730	2,812,140	2,812,140
Net pension liability	15,093,423	-	2,822,530	12,270,893	-
Asset retirement obligation	15,135,086	688,646	-	15,823,732	-
Total long term liabilities	$ 383,689,728	$ 194,767,187	$ 14,035,223	$ 564,421,692	$ 10,677,140

[r] Notes payable reclassified to long term in 2017

(6) Net Position

Net position is composed of the following at December 31:

		2018	2017
Total Plant	$	877,091,133	889,806,691
Less: Total revenue bonds payable		(332,495,381)	(341,614,927)
Contributions in aid of construction		(177,823,955)	(180,608,877)
Notes payable		(191,900,000)	(191,900,000)
Unspent revenue bond proceeds/note proceeds		-	-
Bond proceeds used for bond reserve fund		24,046,945	23,673,741
Bond proceeds used for bond sale costs		1,337,730	1,449,969
Deferred loss on refunding		61,057	248,700
Net investment in capital assets		200,317,529	201,055,297
Debt service account		-	2,098,515
Revenue bond reserve investments		-	23,335,230
Less: Bond proceeds used for bond reserve fund		-	(23,673,741)
Accrued bond interest payable		-	(1,688,922)
Restricted for debt service		-	71,082
Operating reserve - Restricted for operations		15,206,000	14,235,000
Unrestricted		69,716,192	54,095,867
Total net position	$	285,239,721	269,457,246

(7) Retirement Plans

Substantially all regular employees of the Utility are covered by one of the following plans:

(a) IBEW Plans

Defined Benefit Plan

The Utility's IBEW members participate in a cost-sharing defined benefit plan, *the Alaska Electrical Pension Plan of the Alaska Electrical Pension Fund* (IBEW Plan). The Alaska Electrical Trust Funds (AETF) Board of Trustees administers the IBEW Plan and has the authority to establish and amend benefit terms and approve changes in employer required contributions. Each year, AETF issues annual financial reports that can be obtained by writing the plan administrator, Alaska Electrical Pension Trust, 2600 Denali Street, Suite 200, Anchorage, Alaska, 99503. The Utility had 166 and 176 employees covered by the Plan as of December 31, 2018 and 2017, respectively.

The IBEW Plan provides several levels of retirement benefits, including early retirement, normal retirement, late retirement, and disability retirement and includes several options for spouse participation and death benefits. The Utility contributes to the IBEW Plan for its covered employees according to the terms of its Agreement Covering Terms and Conditions of Employment (Agreement) with the IBEW Local 1547. The Agreement in effect during January and February 2017 expired on December 31, 2016. A new agreement was approved subsequent to year end and is effective from February 28, 2017 to December 31, 2019. The Agreement automatically renews for a period of one year from its expiration date and for successive periods of one year each thereafter for so long as there is no proper notification of an intent to negotiate a successor Agreement.

Employer contributions are determined from hours of work reported by participating employers and the contractual employer contribution rate in effect. The Utility's required contribution to the IBEW Plan for each hour for which compensation is paid to the employee for January 1, 2018 to December 31, 2018 was $7.95, February 28, 2017 to December 31, 2017 was $7.85, and from January 1, 2016 to February 27, 2017 was $7.75. The Utility's total employer contributions to the IBEW Plan for 2018 and 2017 were $3,382,920 and $3,272,545, respectively. The Utility had $119,769 and $251,784 in required contributions to the IBEW Plan payable to AETF at December 31, 2018 and 2017, respectively. These amounts are paid during the normal course of business in the month following each year end. The Utility is not subject to withdrawal penalties, nor are there any future minimum payments to the IBEW Plan required other than the contribution per hour compensated as required by the Agreement.

Defined Contribution Plan - Money Purchase Plan

The Agreement requires employer contributions to be made in an amount of 1.9% of each employee's gross wages to the Alaska Electrical Workers Money Purchase Plan (Money Purchase Plan). The Utility's employer and employee contributions to the Money Purchase Plan during 2018 were $437,345 and $89,841, respectively. The Utility's employer and employee contributions to the Money Purchase Plan during 2017 were $499,127 and $98,610, respectively. One hundred percent (100%) of the Utility's required contributions to the IBEW plans have been made through these contributions to the AETF.

(b) State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III)

General Information About the Plan

The Municipality participates in the Alaska Public Employees' Retirement System (PERS I-III or the Plan). PERS I-III is a cost-sharing multiple employer plan which covers eligible State and local government employees, other than teachers. The Plan was established and is administered by the State of Alaska Department of Administration. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

The Plan provides for retirement, death and disability, and post-employment health care benefits. There are three tiers of employees, based on entry date. For all tiers within the Defined Benefit (DB) plan, full retirement benefits are generally calculated using a formula comprised of a multiplier times the average monthly salary (AMS) times the number of years of service. The multiplier is increased at longevity milestone markers for most employees.

The tiers within the Plan establish differing criteria regarding normal retirement age, early retirement age, and the criteria for calculation of AMS, COLA adjustments, and Other Post-Employment Benefits (OPEB) benefits.

A complete benefit comparison chart is available at the website noted below.

The Plan is included in a comprehensive annual financial report that includes financial statements and other required supplemental information. That report is available via the internet at http://doa.alaska.gov/drb/pers. Actuarial valuation reports, audited financial statements, and other detailed plan information are also available on this website. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811-0203 or by phoning (907) 465-4460.

The PERS I-III DB Plan was closed to new entrants effective June 30, 2006. New employees hired after that date participate in the PERS IV Defined Contribution (DC) Plan described later in this note.

Historical Context and Special Funding Situation

In April 2008, the Alaska Legislature passed legislation converting the previously existing PERS plan from an agent-multiple employer plan to a cost-sharing plan with an effective date of July 1, 2008. In connection with this conversion, the State of Alaska passed additional legislation which statutorily capped the employer contribution rate, established a state funded "on-behalf" contribution (subject to funding availability), and required that employer contributions be calculated against all PERS eligible wages, including wages paid to participants of the PERS Tier IV defined contribution plan described later in this note.

Alaska Statute requires the State of Alaska to contribute to the Plan an amount such that, when combined with the employer contribution, is sufficient to pay the Plan's past service liability contribution rate as adopted by the Alaska Retirement Management Board.

Although current statutes call for the State of Alaska to contribute to the Plan, the Alaska Department of Law determined that the statute does not create a legal obligation to assume the liabilities of the Plan; rather it establishes a contribution mechanism to provide employer relief against the rising contribution rates. This relief payment is subject to funding availability, and therefore not legally mandated. As a result, the State initially determined that the Plan is not in a special funding situation. Following much discussion with various stakeholders, participant communities, attorneys, auditors, and the GASB itself, the State has subsequently reversed its position on this matter, and as of June 30, 2015, the State did record the liability presuming that the current statute does constitute a special funding situation as the legislation is currently written. It is important to note that the Alaska Legislature has the power and authority to change the aforementioned statute through the legislative process, and it is likely that the State will pursue efforts to do so in a future legislative session. For the current year financial statements, management has treated AS 39.35.255 as constituting a special funding situation under GASB Statement No. 68 rules and has recorded all pension related liabilities, deferred inflows and outflows of resources, and disclosures on this basis.

Employee Contribution Rates
Regular employees are required to contribute 6.75 percent of their annual covered salary.

Employer and Other Contribution Rates
There are several contribution rates associated with the pension and healthcare contributions and related liabilities. These amounts are calculated on an annual basis.

Employer Effective Rate
This is the contractual employer pay-in rate. Under current legislation, this rate is statutorily capped at 22 percent of eligible wages, subject to a wage floor, and other termination events. This 22 percent rate is calculated on all PERS participating wages, including those wages attributable to employees in the defined contribution plan. Contributions derived from the defined contribution employees are referred to as the Defined Benefit Unfunded Liability (DBUL) contribution.

Alaska Retirement Management Board (ARM) Adopted Rate
This is the rate formally adopted by the ARM Board. This rate is actuarially determined and used to calculate annual Plan funding requirements, without regard to the statutory rate cap or the GASB accounting rate. Prior to July 1, 2015, there were no constraints or restrictions on the actuarial cost method or other assumptions used in the ARM Board valuation. Effective July 1, 2015, the Legislature requires the ARM Board to adopt employer contribution rates for past service liabilities using a level percent of pay method over a closed 25 year term which ends in 2039. This will result in lower ARM Board Rates in future years (as demonstrated in the contribution rate tables below).

On-behalf Contribution Rate
This is the rate paid in by the State as an on-behalf payment under the current statute. The statute requires the State to contribute, based on funding availability, an on-behalf amount equal to the difference between the ARM Board Rate and the Employer Effective Rate. In the financial statements, the on-behalf amounts reflect revenue and expense only during the measurement period July 1, 2017 to June 30, 2018, in which the Plan recognizes the payments, resulting in a significant timing difference between the cash transfers and revenue and expense recognition. Total on-behalf amounts recognized as of the measurement period are actuarially calculated.

GASB Rate
This is the rate used to determine the long-term pension and healthcare liability for plan accounting purposes in accordance with generally accepted accounting principles as established by GASB. Certain actuarial methods and assumptions for this rate calculation are mandated by GASB. Additionally, the GASB Rate disregards all future Medicare Part D payments. For Fiscal Years 2018 and 2017, the GASB rate uses an 8 percent pension and healthcare discount rate.

The GASB Rate and the ARM Board Adopted Rate differ significantly as a direct result of variances in the actuarial methods and assumptions used.

Contribution rates for the years ended June 30, 2017 and June 30, 2018 were determined in the June 30, 2015 and June 30, 2016 actuarial valuations, respectively. Municipality contribution rates for the 2018 and 2017 calendar year were as follows:

January 1, 2018 to June 30, 2018	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	17.12%	21.90%	3.01%	29.07%
Postemployment healthcare (ARHCT)	4.88%	3.11%	0.00%	66.85%
Total Contribution Rates	22.00%	25.01%	3.01%	95.92%

July 1, 2018 to December 31, 2018	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	16.17%	23.21%	5.58%	32.11%
Postemployment healthcare (ARHCT)	5.83%	4.37%	0.00%	87.90%
Total Contribution Rates	22.00%	27.58%	5.58%	120.01%

January 1, 2017 to June 30, 2017	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	14.96%	20.34%	4.14%	24.49%
Postemployment healthcare (ARHCT)	7.04%	5.80%	0.00%	56.64%
Total Contribution Rates	22.00%	26.14%	4.14%	81.13%

July 1, 2017 to December 31, 2017	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	17.12%	21.90%	3.01%	29.07%
Postemployment healthcare (ARHCT)	4.88%	3.11%	0.00%	66.85%
Total Contribution Rates	22.00%	25.01%	3.01%	95.92%

In 2018 and 2017, the Utility's proportionate share of the Municipality's share was 3.14 and 3.53 percent, respectively and was credited with the following contributions into the pension plan.

	Measurement Period	Utility's Fiscal Year	Measurement Period	Utility's Fiscal Year
	July 1, 2017 to June 30, 2018	January 1, 2018 to December 31, 2018	July 1, 2016 to June 30, 2017	January 1, 2017 to December 31, 2017
Employer contributions (including DBUL)	$ 968,982	$ 936,339	$ 856,632	$ 940,338
Nonemployer contributions (on-behalf)	225,603	323,645	309,913	273,320
Total Contributions	$ 1,194,585	$ 1,259,984	$ 1,166,545	$ 1,213,658

In addition, employee contributions to the Plan totaled $264,652 and $289,916 during the Utility's calendar years 2018 and 2017, respectively.

Pension Liabilities, Pension Expense, Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions

The Utility's portion of the Municipality's liabilities, pension expense, deferred outflows and inflows of resources related to pensions are based on its share of the Municipality's contributions to the plan in the current year. Those proportions are 3.14% and 3.53% at December 31, 2018 and 2017, respectively.

At December 31, 2018 and 2017, the Municipality reported a liability for its proportionate share of the net pension liability (NPL) that reflected a reduction for State pension support provided to the Municipality. The amount recognized by the Municipality and the Utility for their proportional share, the related State proportion, and the total were as follows:

December 31,	2018		2017	
	Municipality	Utility	Municipality	Utility
Proportionate Share of NPL	$ 361,285,220	$ 11,361,736	$ 347,836,470	$ 12,270,893
State's proportionate share of NPL associated with the Municipality	$ 104,636,568	$ 3,290,622	$ 129,589,885	$ 4,571,641
Total Pension Liability	$ 465,921,788	14,652,358	$ 477,426,355	16,842,534

The total pension liability for the June 30, 2018 measurement date was determined by an actuarial valuation as of June 30, 2017 rolled forward to June 30, 2018 to calculate the net pension liability as of that date. The total pension liability for the June 30, 2017 measurement date was determined by an actuarial valuation as of June 30, 2016 rolled forward to June 30, 2017 to calculate the net pension liability as of that date. The Municipality's proportion of the net pension liability was based on a projection of the Municipality's long-term share of contributions to the pension plan relative to the projected contributions of all participating entities, including the State, actuarially determined. At the June 30, 2018 measurement date, the Utility's proportion was .2286 percent, which was an increase of .0087 percent from its proportion measured as of June 30, 2017. At the June 30, 2017 measurement date, the Utility's proportion was .2373 percent, which was a decrease of .0327 percent from the prior year.

The Utility recognized pension expense of ($1,504,718) and $573,752 for the year ended December 31, 2018 and December 31, 2017, respectively, of which $154,073 and $336,953 were recorded as on-behalf revenue and expense for additional contributions paid by the State.

At December 31, 2018 and 2017, the Utility reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

	Measurement Period June 30, 2018		Measurement Period June 30, 2017	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (285,157)	$ -	$ (206,881)
Changes in assumptions	-	-	-	-
Net difference between projected and actual earnings on pension plan investments	250,929	-	356,477	-
Changes in proportion and differences between Utility contributions and proportionate share of contributions	412,990	-	130,754	(796,532)
Utility contributions subsequent to the measurement date	491,593	-	636,903	-
Total Deferred Outflows and Deferred Inflows Related to Pensions	$ 1,155,512	$ (285,157)	$ 1,124,134	$ (1,003,413)

At December 31, 2018, the $491,593 reported as deferred outflows of resources related to pensions resulting from contributions subsequent to the measurement date will be recognized as a reduction in the net pension liability in the year ended December 31, 2019. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Year Ending December 31,	Net Amortization of Deferred Outflows and Deferred Inflows of Resources
2019	$ 446,980
2020	137,207
2021	(194,423)
2022	(11,002)
Total Amortization	$ 378,762

Actuarial Assumptions

The total pension liability for the measurement period ended June 30, 2018 was determined by an actuarial valuation as of June 30, 2017, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2018. The total pension liability for the measurement period ended June 30, 2017 was determined by an actuarial valuation as of June 30, 2016, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2017. The actuarial assumptions used in the June 30, 2017 actuarial valuation (latest available) were based on the results of an actuarial experience study for the period from July 1, 2009 to June 30, 2013, resulting in changes in actuarial assumptions adopted by the Alaska Retirement Management Board to better reflect expected future experience. There were no changes to the actuarial assumptions for 2018 and 2017.

Inflation	3.12%
Actuarial Cost Method	Entry Age Normal- Level Percentage of Payroll
Allocation Methodology	Amounts for the June 30, 2018 measurement date were allocated to employers based on the present value of contributions for FY2020-FY2039, as determined by projections based on the June 30, 2017 valuation.
Salary Increases	For peace officers/firefighters, increases range from 9.66 percent to 4.92 percent, based on service. For all others, increases range from 8.55 percent to 4.34 percent, based on age and service.
Investment Return / Discount Rate	8.00 percent, net of pension plan investment expenses. This is based on an average inflation rate of 3.12 percent and real rate of return of 4.88 percent.
Mortality (Pre-termination)	Based upon 2010-2013 actual mortality experience, 60% of male and 65% of female post-termination mortality rates. Deaths are assumed to be occupational 70% of the time for Peace Officers/Firefighters, 50% of the time for Others.
Mortality (Post-termination)	Based upon the 2010-2013 actual mortality experience. 96% of all rates of the RP-2000 table, 2000 Base Year projected to 2018 with Projection Scale BB.

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class.

These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The best estimates of arithmetic real rates of return for each major asset class included in the pension plan's target asset allocation as of the measurement period June 30, 2018 and 2017 are summarized in the following table (note that the rates shown below exclude the inflation component):

June 30, 2018

Asset Class	Long-term Expected Real Rate of Return	Target Allocation	Range
Domestic equity	8.90%	24%	+/- 6%
Global ex-U.S. equity	7.85%	22%	+/- 4%
Fixed income	1.25%	10%	+/- 5%
Opportunistic	4.76%	10%	+/- 5%
Real assets	6.20%	17%	+/- 8%
Absolute return	4.76%	7%	+/- 4%
Private equity	12.08%	9%	+/- 5%
Cash equivalents	0.66%	1%	+3/-1

June 30, 2017

Asset Class	Long-term Expected Real Rate of Return	Target Allocation	Range
Domestic equity	8.83%	26%	+/- 6%
Global ex-U.S. equity	7.79%	22%	+/- 4%
Intermediate treasuries	1.29%	9%	+/- 5%
Opportunistic	4.76%	17%	+/- 8%
Real assets	4.94%	7%	+/- 4%
Absolute return	4.76%	13%	+/- 5%
Private equity	12.02%	5%	+/- 2%
Cash equivalents	0.63%	1%	+/- 3/-1

Discount Rate

The discount rate used to measure the total pension liability was 8 percent in 2018 and 2017. The projection of cash flows used to determine the discount rate assumed that Employer and State contributions will continue to follow the current funding policy which meets State statutes. Based on those assumptions, the pension plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Discount Rate Sensitivity

The following presents the Utility's proportionate share of the net pension liability calculated using the discount rate of 8 percent, as well as what the Utility's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage-point lower (7 percent) or 1-percentage-point higher (9 percent) than the current rate:

June 30, 2018

	Proportional Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utility's proportionate share of the net pension liability	0.022865%	$ 15,045,805	$ 11,361,736	$ 8,245,459

June 30, 2017

	Proportional Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utility's proportionate share of the net pension liability	0.23737%	$ 16,118,950	$ 12,270,893	$ 9,021,357

Pension Plan Fiduciary Net Position
Detailed information about the pension plan's fiduciary net position is available in the separately issued PERS financial report.

(c) State of Alaska Public Employees' Retirement System Defined Contribution Plan (PERS IV)

Plan Information
The Municipality participates in the Alaska Public Employees' Retirement System (PERS IV or (Plan). PERS IV is a Defined Contribution (DC) plan which covers eligible State and local government employees, other than teachers. The Plan was established and is administered by the State of Alaska Department of Administration. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

The Plan is included in a comprehensive annual financial report that includes financial statements and other required supplemental information. That report is available via the internet at http://doa.alaska.gov/drb/pers. Actuarial valuation reports, audited financial statements, and other detailed plan information are also available on this website. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811 0203 or by phoning (907) 465 4460.

Plan Participation and Benefit Terms
The Plan is governed by Section 401(a) of the Internal Revenue Code. A portion of employee wages and a matching employer contributions are made to the Plan before tax. These contributions plus any change in value (interest, gains and losses), and minus any Plan administrative fees or other charges, are payable to the employee or the employee's beneficiary at a future date. The Plan is a participant-directed plan with investment options offered by providers that are selected by the ARM Board.

Employees first enrolling into PERS after July 1, 2006 participate in PERS IV. PERS IV is a defined contribution retirement plan that includes a component of defined benefit post-employment health care.

Plan Contribution Requirements

The Plan requires both employer and employee contributions. Employees may make additional contributions into the Plan, subject to limitations. Contribution rates are as follows:

	Tier IV	
	1/1 - 6/30	7/1 - 12/31
Employee Contribution	8.00%	8.00%
Employer Contribution		
Retirement	5.00%	5.00%
Health Reimbursement Arrangement	3.00%	3.00%
Retiree Medical Plan	1.03%	0.94%
Death & Disability Benefit	0.16%	0.26%
Total Employer Contribution	9.19%	9.20%

(d) State of Alaska Public Employees' Retirement System OPEB Plans

General Information About the Plans

As part of its participation in the PERS Defined Benefit Plan (Tiers I, II, III), which is a cost-sharing multiple employer plan, the Utility participates in the Alaska Retiree Healthcare Trust (ARHCT), Retiree Medical Plan (RMP) and Occupational Death and Disability Plan (ODD). The ARHCT is self-funded and provides major medical coverage to retirees of the Defined Benefit Plan. Benefits vary by Tier level. The RMP provides major medical coverage to retirees of the PERS Defined Contribution Plan (Tier IV). The ODD provides death benefits for beneficiaries of plan participants and long-term disability benefits to all active members within PERS. The Plans are administered by the State of Alaska, Department of Administration. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811-0203 or by phoning (907) 465-4460.

Employer Contribution Rate

The Utility is required to contribute the following percentages of covered payroll into the OPEB plans: ARHCT, 4.88%, ODD, 0.43%, and RMP, 1.03%. Employees do not contribute. In 2018, the Utility was credited with the following contributions to the OPEB plans:

	Measurement Period July 1, 2017 to June 30, 2018	Utility's Fiscal Year January 1, 2018 to December 31, 2018
Employer contributions- ARHCT	$ 276,203	$ 303,957
Employer contributions- ODD	7,635	11,425
Employer contributions- RMP	31,005	31,365
Total Contributions	$ 314,843	$ 346,747

OPEB Liabilities, OPEB Expense, and Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB Plans

At December 31, 2018, the Utility reported a liability for its proportionate share of the net OPEB liabilities (NOL) that reflected a reduction for State OPEB support provided to the Utility. The Utility reported a net OPEB asset (NOA) for ODD. The amount recognized by the Utility for its proportional share, the related State proportion, and the total were as follows:

		2018
Utility's proportionate share of NOL- ARHCT	$	2,346,143
Utility's proportionate share of NOL- RMP		33,844
Utility's proportionate share of NOA - ODD		(51,655)
Utility's Net OPEB liability	$	2,328,332
State's proportionate share of ARHCT NOL associated with the Utility		681,062
Total Net OPEB Liabilities	$	3,009,394

The total OPEB liabilities for the June 30, 2018 measurement date was determined by an actuarial valuation as of June 30, 2017 rolled forward to June 30, 2018 to calculate the net OPEB liabilities as of that date. The Utility's proportion of the net OPEB liabilities were based on a projection of the Utility's long-term share of contributions to the OPEB plans relative to the projected contributions of all participating entities, actuarially determined. The Utility's proportionate share at the June 30, 2018 measurement date increased over the proportionate share as of the June 30, 2017, as shown below.

Utility's proportionate share of the net OPEB liabilities:	Measurement Date June 30, 2017	Measurement Date June 30, 2018	Change
ARHCT	0.22046%	0.22860%	0.00814%
RMP	0.25969%	0.26596%	0.00627%
ODD	0.25969%	0.26596%	0.00627%

As a result of its requirement to contribute to the Plans, the Utility recognized net OPEB expense of ($8,830), which includes $89,409 of on-behalf expense, and on-behalf revenue of $89,409 for actuarially calculated support provided by the State for the AHRCT plan. At December 31, 2018, the Utility reported deferred outflows of resources and deferred inflows of resources related to OPEB plans from the following sources:

	Measurement Period June 30, 2018	
	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (267,153)
Changes in assumptions	371,612	-
Net difference between projected and actual earnings on pension plan investments	-	(503,921)
Changes in proportion and differences between Utility contributions and proportionate share of contributions	171,440	(72,359)
Utility contributions subsequent to the measurement date	201,633	-
Total Deferred Outflows and Deferred Inflows Related to OPEB Plans	$ 744,685	$ (843,433)

The $201,633 reported as deferred outflows of resources related to OPEB resulting from contributions made subsequent to the measurement date will be recognized as a reduction in the net OPEB liability in the year ended December 31, 2019. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to OPEB will be recognized in OPEB expense as follows:

Year Ending December 31,	Net amortization of Deferred Outflows and Deferred Inflows of Resources
2019	$ (68,663)
2020	(57,450)
2021	(164,193)
2022	(10,730)
2023	153
Thereafter	501
Total amortization	$ (300,382)

Actuarial Assumptions

The total OPEB liability for the measurement period ended June 30, 2018 (Utility calendar year 2018) was determined by an actuarial valuation as of June 30, 2017, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2018. The actuarial assumptions used in the June 30, 2017 actuarial valuation (latest available) were based on the results of an actuarial experience study for the period from July 1, 2009 to June 30, 2013, resulting in changes in actuarial assumptions adopted by the Alaska Retirement Management Board to better reflect expected future experience.

Actuarial cost method	Entry age normal; level percentage of payroll
Amortization method	Level dollar, closed
Inflation	3.12%
Salary Increases	Graded by service from 8.55 percent to 4.34 percent, for all others.
Allocation methodology	Amounts for the June 30, 2018 measurement date were allocated to employers based on the projected present value of contributions for FY2020-FY2039. The liability is expected to go to zero at 2039.
Investment Return / Discount Rate	8.00 percent, net of postemployment healthcare plan investment expenses. This is based on an average inflation rate of 3.12 percent and real rate of return of 4.88 percent.
Healthcare cost trend rates	Pre-65 medical; 8.0 percent grading down to 4.0 percent Post-65 medical; 5.5 percent grading down to 4.0 percent Prescripion drug; 9.0 percent grading down to 4.0 percent
Mortality (Pre-termination)	Based upon 2010-2013 actual mortality experience, 60% of male and 65% of female post-termination mortality rates. Deaths are assumed to be occupational 50% of the time for Others.
Mortality (Post-termination)	96% of all rates of the RP-2000 table, 2000 Base Year projected to 2018 with Projection Scale BB.

The long-term expected rate of return on OPEB plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of postretirement healthcare plan investment expense and inflation) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The best estimates of arithmetic real rates of return for each major asset class are summarized in the following table (note that the rates shown below exclude the inflation component):

Asset Class	Long-term Expected Real Rate of Return	Target Allocation
Domestic equity	8.90%	24%
Global ex-U.S. equity	7.85%	22%
Fixed income	1.24%	10%
Opportunistic	4.76%	10%
Real assets	6.20%	17%
Absolute return	4.76%	7%
Private equity	12.08%	9%
Cash equivalents	0.66%	1%

Discount Rate

The discount rate used to measure the total OPEB liability was 8.00% for each plan. The projection of cash flows used to determine the discount rate assumed that employer and State contributions will continue to follow the current funding policy which meets State statutes. Based on those assumptions, the OPEB plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on OPEB plan investments was applied to all periods of projected benefit payments to determine the total OPEB liability for each plan.

Discount Rate Sensitivity

The following presents the Utility's proportionate share of the net OPEB liabilities calculated using the discount rate of 8.00%, as well as what the Utility's proportionate share of the net OPEB liabilities would be if it were calculated using a discount rate that is 1-percentage-point lower (7.00%) or 1-percentage-point higher (9.00%) than the current rate:

	Proportional Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utility's proportionate share of the NOL- ARHCT	0.22860%	$ 4,749,764	$ 2,346,143	$ 331,417
Utility's proportionate share of the NOL- RMP	0.26596%	101,066	33,844	(18,588)
Utility's proportionate share of the NOL- ODD	0.26596%	(48,506)	(51,655)	(54,246)

Healthcare Cost Trend Rate Sensitivity

The following presents the Utility's proportionate share of the net OPEB liabilities as of June 30, 2018, calculated using the healthcare cost trend rates as summarized in the 2018 actuarial valuation report, as well as what the respective Plan's net OPEB liability would be if it were calculated using trend rates that are one-percentage-point lower or one-percentage-point higher than the current healthcare cost trend rates (in thousands):

	Proportional Share	1% Decrease	Healthcare Cost Trend Rate	1% Increase
Utility's proportionate share of the NOL- ARHCT	0.22860%	$ 45,543	$ 2,346,143	$ 5,117,441
Utility's proportionate share of the NOL- RMP	0.26596%	(28,774)	33,844	117,646
Utility's proportionate share of the NOL- ODD	0.26596%	-	(51,655)	-

OPEB Plan Fiduciary Net Position

Detailed information about the OPEB plan's fiduciary net position is available in the separately issued PERS financial report.

(e) State of Alaska Public Employees' Retirement System Defined Contribution OPEB Plan

General Information About the Plans

Defined Contribution Pension Plan participants (PERS Tier IV) participate in the Occupational Death and Disability Plan (ODD), and the Retiree Medical Plan (RMP). Information on these plans is included in the comprehensive annual financial report for the PERS Plans noted above. These plans provide for death, disability, and postemployment healthcare benefits.

Employer Contribution Rates

Employees do not contribute to the Defined Contribution OPEB plans. Employer contribution rates for the year ended December 31, 2018 were as follows:

	Tier IV	
	1/1 - 6/30	7/1 - 12/31
Employer Contribution		
Health Reimbursement Arrangement	3.00%	3.00%
Retiree Medical Plan	1.03%	0.94%
Death & Disability Benefit	0.16%	0.26%
Total Employer Contribution	4.19%	4.20%

Healthcare Reimbursement Arrangement
In addition, PERS defined contribution members also participate in the Health Reimbursement Arrangement. AS 39.30.370 requires that the employer contribute "an amount equal to three percent of the employer's average annual employee compensation of *all employees of all employers* in the plan". Prior to July 1, 2018 a flat rate of approximately $2,084 per year for full time employees and $1.34 per part time hour worked was paid. For pay periods ending after July 1, 2018, a flat rate of approximately $2,103 per year for full time employees and $1.35 per part time hour worked were paid.

The Utility contributed $159,988 and $127,200 to PERS IV for retirement and retiree medical on behalf of its employees for the years ended December 31, 2018 and 2017, respectively. The Utility also contributed $79,922 and $66,221 for Health Reimbursement Arrangement for 2018 and 2017, respectively. Employee contributions to the Plan totaled $256,006 and 203,507 for 2018 and 2017, respectively.

Annual Postemployment Healthcare Cost
In 2018, the Utility contributed $122,740 in Defined Contribution OPEB costs. These amounts have been recognized as expenses.

(8) Commitments and Contingencies

The Utility, in the normal course of its activities, is involved in various claims and pending litigation. In the opinion of management and the Municipality's legal department, the disposition of these matters is not expected to have a material adverse effect on the Utility's financial statements.

(a) Environmental

Fuel/Polychlorinated Biphenyl (PCB) Contaminated Sites at Hank Nikkels Power Plant 1 and Operations/Dispatch Center

During the 1964 earthquake, approximately 250,000-400,000 gallons of diesel fuel spilled on the ground. Based on numerous environmental investigations, the spill impacted soil and groundwater at the Hank Nikkels Power Plant 1 and properties west/northwest of the plant. During the 2006-2007 subsurface investigation, in addition to diesel contamination known from the 1964 spill, PCBs were detected in the soil. All soil disturbing activities at the site are governed by the Risk-Based Disposal Plan (RBDP) administered by the Alaska Department of Environmental Conservation (ADEC) and the Environmental Protection Agency (EPA).

In May 2017 the Utility conducted PCB cleanup activities at the plant and paved the surface of the cleanup area in accordance with the 2008 RBDP approved by EPA and ADEC. The Utility recorded a liability for estimated cleanup costs of $760,000 at December 31, 2016. At December 31, 2017 the liability remained at $511,787. All cleanup activities were considered to be performed and the liability was discharged during 2018.

In 2009 PCB contaminated soil was discovered near the Operations/Dispatch building during excavation to install water lines for a fire suppression system. In 2010 and 2015 additional site investigations were conducted to determine a horizontal and vertical extent of PCB contamination. Following the soil investigations the Utility performed monitoring of groundwater at the site and in the vicinity during 2015 and 2016. Analytical results indicated no off-site migration of PCBs. The Utility is waiting on EPA's review of the site data and further decisions. The cost associated with any further actions cannot be determined at this time.

Petroleum Contaminated Sites and Spill Cleanup

In 2017, ADEC conducted a review of three contaminated sites that have a long history of monitoring and identified two sites that qualified for cleanup complete status and one site (Transformer Shop) that could possibly qualify for the Cleanup Complete with Institutional Controls status if the Utility conducts additional sampling.

In 2018 based on an ADEC request, the Utility conducted a vapor intrusion assessment associated with the old petroleum contamination in the subsurface near and under the Transformer Shop. The assessment concluded that there were no petroleum vapors entering the Transformer Shop from the subsurface. In response to the assessment, ADEC requested to continue biennial groundwater monitoring at this site and include additional volatile organic compounds into the monitoring program. The Utility intends to prepare a work plan with additional testing for the 2020 biennial groundwater monitoring. As a result of the November 30, 2018 earthquake, a few transformers failed and oil was spilled to the ground. The utility performed an initial cleanup upon discovery of the spills and an additional assessment in the spring. The Utility does not anticipate material environmental liability associated with these spills.

Compliance with Air Quality Permits

The Utility owns three turbines that are subject to hourly and annual emissions limits emission controls for criteria pollutants, NOx and CO. In addition to maintaining continuous emission monitoring systems (CEMS) on each turbine, the two newly installed turbines requires operation with post-combustion emission controls. EPA regulations require annual third party emissions testing to assure accuracy of the CEMS. Newly installed turbines have significant emissions reductions compared to the existing turbines, however maintaining emissions control equipment and performing all testing required by EPA will add to the overall environmental compliance cost. The Utility will oversee environmental compliance and contract qualified third-party experts to perform necessary services. Environmental permitting and compliance will continue to require a consultant's expertise. The cost of compliance cannot be determined at this time.

(b) Petroleum Production Tax (PPT)

For tax year 2018, the Utility estimated that its PPT liability under AS 43.55.011(e) for non-royalty gas is zero and its liability under AS 43.44.011(i) for private royalty gas is $4,370. Monthly installment payments from February 2018 through January 2019 totaled $104,554.

For tax year 2017, the Utility estimated that its PPT liability under AS 43.55.011(e) for non-royalty gas is $604,171 and its liability under AS 43.44.011(i) for private royalty gas was $5,209. Monthly installment payments from February 2017 through January 2018 totaled $609,380.

(c) Petroleum Production Credits

Pursuant to AS 43.55.023, the Utility applies for Alaska oil and gas tax credits from the State of Alaska Department of Revenue (DOR). The Utility records the receipt of cash from tax credits as a restricted investment and as a deferred inflow of resources for the benefit of customers. During 2018 and 2017, the Utility did not apply for tax credits. During 2017, the Utility received cash payments of $20,294 for calendar year 2015 credits. The amounts received by the Utility are subject to final resolution of DOR audits, and are not recorded until cash is received.

(d) Contractual Commitments

The Utility has purchase commitments to contractors and suppliers at December 31, 2018 of approximately $7.8 million. Those commitments are for contracts, materials and services related to construction of the Utility's generation and distribution system assets, regulatory filings and contracted billing services. Construction of plant assets is financed with contributions in aid of construction and Utility equity, and operating commitments are financed with Utility revenues.

(9) Regulatory Matters

(a) Beluga River Unit Underlift Settlements

Until April 2016 the Utility owned a one-third interest in annual production of the BRU. Its field partners at that time - CPAI and Hilcorp Alaska, LLC - each also owned a one-third interest in BRU production. Every BRU owner has a right to take a portion of annually produced gas proportionate to its interest.

In 2005 the Utility underlifted (i.e. took less than its interest in BRU's annual output) and accepted a monetary settlement from its field partners. These funds were deposited in a Future Natural Gas Purchases Account (FGP), and the Utility recorded deferred inflows of resources for future natural gas purchases. The balances of the Future Natural Gas Purchases Account, as of December 31, 2018 and 2017 were $17,934,651 and $17,230,809, respectively.

In 2015 the Utility petitioned the RCA for authorization to apply 2014 underlift settlement proceeds to reduce its GTP in effect from July 1, 2016 through June 30, 2017. The RCA approved the Utility's unopposed proposal in Order U-15-116(2), dated March 10, 2016.

In April 2016 the Utility purchased 70% of CPAI's one-third interest in the BRU. The RCA approved the Utility's request in Order U-16-012(14), dated April 21, 2016, to utilize a closing underlift settlement from CPAI of $13,177,726 towards financing this acquisition. See Note 9(f).

(b) Regulatory Debits/Credits

The Utility files a COPA rate quarterly with the RCA to recover cost of power expenses not recovered in base rates. The COPA calculation is based on the projected cost of fuel and purchased power for the applicable quarter, the projected kilowatt hour sales for the applicable quarter, and the over- or under- recovered balance in the cost of power clearing account. The Utility records in the cost of power clearing account an asset with an offsetting credit to a contra revenue account for under recovered costs or a liability and an offsetting debit to a contra revenue account for over recovered costs. The Utility under-recovered as of December 31, 2018 in the amount of $1,904,402 and over-recovered as of December 31, 2017 in the amount of $4,589,934.

Prior to October 24, 2017, the Utility annually set the GTP with its third quarter COPA filings. (See Note 9 (g) for the new schedule in filing the GTP.) Through the GTP, the Utility recovers the Gas Fund's annual revenue requirement associated with the Utility's ownership interest in the BRU and any over or under recovery from the prior year. The Utility records in the cost of Gas Transfer Price Clearing Account an asset and a credit to an expense account for under-recovered costs or a liability and debit to an expense account for over-recovered costs. The Utility under-recovered as of December 31, 2018 in the amount of $4,793 and over-recovered as of December 31, 2017 in the amount of $7,394,724.

(c) Deferred Regulatory Liability for Gas Sales

Revenue from third party sales of natural gas produced at the BRU is excluded from the GTP calculation. These funds, net of royalties and the ARO surcharge, are recorded in the Utility's Future BRU Construction or Natural Gas Purchases account, reported on the statement of net position as deferred inflows of resources, and referred to for regulatory purposes as the Deferred Regulatory Liability from Gas Sales (DRLGS) Account. These funds are to be used for future BRU construction or natural gas purchases. The balances of the DRLGS account, as of December 31, 2018 and 2017, were $8,077,741 and $25,002,529, respectively.

(d) Asset Retirement Obligation Sinking Fund

ARO expenses associated with future abandonment of the BRU are funded through a surcharge to the Utility's GTP. This surcharge is deposited into a sinking fund. As of December 31, 2018 and 2017, the sinking fund account balances were $13,915,853 and $13,198,877, respectively.

(e) Revenue Requirement Studies

On December 30, 2016 the Utility filed a petition with the RCA, based on a 2015 test year revenue requirement study, for interim and permanent across-the-board rate increases in energy and demand charges in order to recover costs associated with its construction of Plant 2A. The Utility requested a 29.49% interim and refundable rate increase, based on RCA approval of the Utility's proposed rate stabilization plan (RSP). On February 13, 2017 the RCA granted the Utility an interim and refundable rate increase of 37.30%, denied approval of the Utility's proposed RSP, and suspended the Utility's request into Docket U-17-008 for further investigation. A public hearing was held on this matter that began on November 16, 2017, and continued through December 21, 2017. The RCA issued a final order on March 23, 2018 [U-17-008(13)] approving a 37.32% increase in the revenue requirement.

In two separate submittals at the Superior Court, Providence Health and Services (PHS) appealed the decision by the RCA on (1) Order 10 - refund order and (2) Order 13 - final order. The Superior Court rendered an Order on Order 13 (final order) on May 20, 2019 - reversing and remanding the RCA Order 13 for further proceedings consistent with the Superior Court's Order and the reasons that supported the Order.

(f) Acquisition of CPAI's Interest in the BRU

In Order U-16-012(14), dated April 21, 2016, the RCA granted a joint petition filed by the Utility and CEA requesting approval of a purchase and sale agreement for the acquisition of CPAI's one-third interest in the BRU. The total purchase price was $152 million, with the Utility acquiring 70% of that interest for $106.4 million and CEA the remaining 30% for $45.6 million. The Utility funded its share of the acquisition with DRLGS and Future Natural Gas Purchases Account funds, cumulative and underlift proceeds owed to it by CPAI. With this purchase the Utility has a 56.67% interest in the BRU.

(g) BRU Ratemaking and Accounting Treatment - Aggregate BRU Interest

On June 20, 2016, the Utility filed for approval from the RCA for some changes in the ratemaking and accounting treatment applicable to the Aggregate BRU Interest. Ruling under Docket U-16-060(12), the RCA granted in part the request on October 24, 2017. The use of rate base/rate of return (RB/ROR) methodology to calculate the gas fund revenue requirement beginning in 2019 was approved. The use of a system-wide weighted average cost of capital (WACC) for calculating the gas fund revenue requirement was approved. The RCA also approved the inclusion of depletion expense using the units of production methodology for calculating the gas fund revenue requirement.

Because the GTP is one component of the COPA and Small Facility Power Purchase Rate (SFPPR), several 2017 tariff advice filings were suspended and were filed under Docket U-16-073. On October 24, 2017, these were approved and made permanent.

(h) Bradley Lake Transmission

Homer Electric Association, Inc. (HEA) filed a rate case on November 15, 2013 requesting RCA's approval of postage stamp rates for Bradley Lake energy wheeled over HEA's system. The Utility intervened, arguing in part that the Bradley Lake Agreements govern the obligations of Bradley Lake participants and that the RCA was statutorily precluded, under AS 42.05.431(c), from reviewing these wheeling rates. On June 30, 2014, the RCA issued an order establishing interim rates for wheeling Bradley Lake energy from the Soldotna to Quartz Creek Substations. The parties appealed to the state superior court, which ruled May 27, 2015 that the RCA lacks jurisdiction over Bradley Lake wheeling rates. All parties appealed this decision to the Alaska Supreme Court. The parties engaged in lengthy mediation, and filed reply briefs with the Alaska Supreme Court. Oral arguments before the Alaska Supreme Court were heard May 31, 2018. On February 22, 2019, the Supreme Court issued an opinion affirming the Superior Court's decision reversing the RCA's order.

(i) Potential acquisition of the Utility by CEA

On April 1, 2019, CEA filed a petition at the RCA requesting necessary approvals for acquiring the Utility from the Municipality and requesting an amendment of Certificate of Public Convenience and Necessity (CPCN) No. 8 to reflect the acquired service territory. This filing is assigned docket U-19-020. CEA has agreed to acquire most of the assets of the Utility from the Municipality. CEA and the Municipality have agreed to a transaction in which CEA will purchase most of the Utility's assets and the generation output of the Utility's share of the Eklutna Hydroelectric Project for a term of 35 years.

On April 5, 2019, the Municipality applied for approval from the RCA to amend its CPCN No. 121 to consist solely of wholesale bulk power sales at the Eklutna generation plant. The Municipality also applied to terminate the restriction on payment of dividends to the Municipality initially imposed by Order No. U-13-184(22). This filing was assigned docket U-19-021.

On May 8, 2019, the RCA ordered the consolidation of U-19-020 and U-19-021. A scheduled hearing starts on August 27, 2019 and continuing as necessary through September 17, 2019. The statutory timeline for issuance of a final order by the RCA in these consolidated dockets is November 19, 2019.

(j) Petition to Adjust Depreciation Rates

On December 31, 2018, the Utility filed a petition at the RCA for approval of revised depreciation rates (docket U-18-121). The study was based on the Utility's electric plant balances and continuing property records as of December 31, 2017. The Utility requested that the depreciation rates be approved for implementation as of the next accounting month following final approval by the RCA. It is expected that the RCA will issue a final order on the proposed depreciation rates on or before June 30, 2019. If approved, rates will be effective July 1, 2019.

(10) Risk Management and Self Insurance

The Municipality is exposed to various risks of loss related to torts; theft of, damage to and destruction of assets; errors and omissions; illness of and injuries to employees; unemployment; and natural disasters. The Municipality utilizes three risk management funds to account for and finance its uninsured risks of loss.

The Municipality provides coverage up to the maximum of $3,000,000 per occurrence for automobile and general liability claims and for each workers' compensation claim. No settled claim exceeded this commercial coverage in 2018, 2017 or 2016.

Unemployment compensation expense is based on actual claims paid by the State of Alaska and reimbursed by the Municipality.

The Utility participates in the Municipality's risk management program and makes payments to the Municipality through inter-governmental charges based on actuarial estimates of the amounts needed to pay prior and current year claims (See Note 1(o).) The Utility does not include any portion of the Municipality's claims payable among its liabilities on the Statements of Net Position.

(11) Other Matters

(a) *Eklutna Hydroelectric Project*

On October 2, 1997, the ownership of the Eklutna Hydroelectric Project was formally transferred from the Alaska Power Administration, a unit of the United States Department of Energy, to the three participating utilities: the Utility, CEA and Matanuska Electric Association (MEA). The project is jointly owned and operated by the participating utilities and each contributes their proportionate share for operation, maintenance, and capital improvement costs, as well as maintenance of the transmission line between Anchorage and the hydroelectric plant. The Utility has a 53.33% ownership interest in the project and recorded costs of $808,836 and $2,300,574 in 2018 and 2017, respectively.

(b) *Bradley Lake Hydroelectric Project*

The Utility agreed to acquire a portion of the output of the Bradley Lake Hydroelectric Project (Project) pursuant to a Power Sales Agreement (Agreement). The Agreement specifies the Utility acquire 25.9% of the output of the Project.

The Project went on line September 1, 1991. The Utility made payments to the Alaska Energy Authority (AEA) of $5,028,039 in 2018 for its portion of costs, and received 102,307 megawatt hours of power from the Project. In 2017 the Utility paid $4,669,706 and received 95,933 megawatt hours. The Utility received a budget surplus refund in the amount of $374,372 for 2018. The Utility's estimated cost of power from the Project for 2019 is $4,997,622.

AEA issued the Power Revenue Bonds, First and Second Series in September 1989 and August 1990, respectively, for the long term financing of the construction costs of the Project. On July 1, 2010, AEA issued $28,800,000 principal amount of Power Revenue Bonds, Sixth Series. The Sixth Series Bonds were issued for the purpose of refunding the Power Revenue Bonds, Fifth Series Bonds to take advantage of lower interest rates. The total amount of debt outstanding as of December 31, 2018 is $33,470,000. The pro rata share of the debt service costs of the Project for which the Utility is responsible, given its 25.9% share of the Project, is $10,219,881. In the event of payment defaults by other power purchasers, the Utility's share could be increased by up to 25%, which would then cause the Utility's pro rata share of Project debt service to be a total of $11,982,190. The Utility does not now know of or anticipate any such defaults.

(c) *Southcentral Power Project (SPP)*

The Utility entered into a participation agreement with CEA on August 28, 2008, to proceed with the joint development, construction and operation of SPP. SPP went into service on January 31, 2013. It has a capacity of 200.3 MW, of which the Utility's proportionate share is 60.1 MW, or 30%. The Utility has recorded costs of $14,895,085 and $14,639,389 in 2018 and 2017, respectively.

(12) Subsequent Events

Sale of the Utility

On April 3, 2018, Anchorage voters approved an amendment to the Anchorage Municipal Charter authorizing the Municipality to sell the Utility to CEA by Municipal ordinance, to be approved no later than December 31, 2018. The Anchorage Assembly approved the sale on December 4, 2018. In April 2019, both the Municipality and CEA filed applications to the RCA to amend their CPCNs and to approve the sale. (See Note 9(i)).

The Municipality and CEA are currently engaged in limited integration planning and due diligence activities. The Utility continues to operate as usual and the proposed sale has no material effect on ongoing operations of the Utility.

(13) New Accounting Pronouncements

GASB has passed several new accounting standards with upcoming implementation dates. The following new accounting standards were implemented by the Utility for 2018 reporting:

- GASB 75 – *Accounting and Financial Reporting for Postemployment Benefit Plans Other than Pensions*. The provisions of this statement address accounting and financial reporting issues for postemployment benefits other than pensions provided to the employees of state and local governmental employers. This statement establishes standards for recognizing and measuring liabilities, deferred outflows of resources, deferred inflows of resources, and expense/expenditures. For defined benefit OPEB, this statement identifies the methods and assumptions that are required to be used to project benefit payments, discount projected benefit payments to their actuarial present value, and attribute that present value to periods of employee service. Note disclosure and required supplementary information requirements about defined benefit OPEB also are addressed. The Utility applied this statement to the State of Alaska PERS OPEB plans for December 31, 2018 (See Note 2).

- GASB 85 - *Omnibus 2017*. The objective of this statement is to address practice issues that have been identified during implementation and application of certain GASB statements. This statement addresses a variety of topics including issues related to blending component units, goodwill, fair value measurement and application, and postemployment benefits (pensions and OPEB). As of December 31, 2018, the Utility implemented guidance from this statement as it related to OPEB reporting. We considered the other objectives and were determined to be not applicable.

- GASB 86 - *Certain Debt Extinguishment Issues.*
  The primary objective of this statement is to improve consistency in accounting and financial reporting for in-substance defeasance of debt by providing guidance for transactions in which cash and other monetary assets acquired with only existing resources, resources other than the proceeds of refunding debt, are placed in an irrevocable trust for the sole purpose of extinguishing debt. This statement also improves accounting and financial reporting for prepaid insurance on debt that is extinguished and notes to financial statements for debt that is defeased in substance. This Statement was considered and determined to be not applicable at this time. The Utility will consider this guidance in future years.

The following standards are required to be implemented in future financial reporting periods:

- GASB 83 - *Certain Asset Retirement Obligations.* The provisions of this Statement are required to be implemented for the 2019 financial reporting period. Due to the Utility's application of accounting and reporting requirements for regulated operations, the Utility determined this standard to be not applicable.

- GASB 84 - *Fiduciary Activities.* The provisions of this Statement are required to be implemented for the 2019 financial reporting period.

- GASB 87 - *Leases.* The provisions of this Statements are required to be implemented for the 2020 financial reporting period.

- GASB 88 - *Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements.* The provisions of this statement are required to be implemented in the 2019 reporting period.

- GASB 89 - *Accounting for Interest Costs Incurred before the End of a Construction Period.* The provisions of this statement are required to be implemented in the 2020 reporting period.

- GASB 90 - *Majority Equity Interests* - an Amendment of GASB Statements No. 14 and No. 61. The provisions of this statement are required to be implemented in the 2019 reporting period.

- GASB 91 - *Conduit Debt Obligations* - The provisions of this statement are required to be implemented in the 2021 reporting period.

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REQUIRED SUPPLEMENTARY INFORMATION

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Defined Benefit Pension Plan
Schedule of the Utility's Information on the Net Pension Liability

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net Pension Liability(1)	Utility's Proportionate Share of the Net Pension Liability	State of Alaska's Proportionate Share of the Net Pension Liability	Total Utility Net Pension Liability	Utility's Proportion of the Covered Payroll	Utility's Proportionate Share of the Net Pension Liability as a percentage of Payroll	Plan Fiduciary Net Position as a Percentage of the Total Pension Liability
2018	2018	0.22865%	$ 11,361,736	$ 3,290,622	$ 14,652,358	$ 6,907,073	164.49%	65.19%
2017	2017	0.23737%	12,270,893	4,571,641	16,842,534	6,874,310	178.50%	63.37%
2016	2016	0.27003%	15,093,423	1,901,832	16,995,255	7,069,090	213.51%	59.55%
2015	2015	0.21637%	10,494,008	2,810,753	13,304,761	6,832,003	153.60%	63.96%

(1) The Utility's proportionate share of the Net Pension Liability represents Utility's allocated portion of the Municipality's proportionate share for the given year.

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Defined Benefit Pension Plan
Schedule of Utility Contributions

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2018	2018	$ 936,339	$ 936,339	$ -	$ 6,969,518	13.435%
2017	2017	940,338	940,338	-	7,051,257	13.336%
2016	2016	854,217	854,217	-	7,204,870	11.856%
2015	2015	767,929	767,929	-	6,991,594	10.984%

See accompanying notes to Required Supplementary information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of the Utility's Information on the Net OPEB Liability-ARHCT

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net OPEB Liability(1)	Utility's Proportionate Share of the Net OPEB Liability	State of Alaska's Proportionate Share of the Net OPEB Liability	Total Utility Net OPEB Liability	Utility's Covered Payroll	Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Payroll	Plan Fiduciary Net Position as a Percentage of the Total OPEB Liability
2018	2018	0.22860%	$ 2,346,143	$ 681,062	$ 3,027,205	$ 6,907,073	33.97%	88.12%

(1) The Utility's proportionate share of the Net OPEB Liability represents the Utility's allocated portion of the Municipality's proportionate share for the given year.

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of Utility Contributions - ARHCT

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2018	2018	$ 303,957	$ 303,957	$ -	$ 6,969,518	4.361%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of the Utility's Information on the Net OPEB Liability - RMP

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net OPEB Liability(1)	Utility's Proportionate Share of the Net OPEB Liability	State of Alaska's Proportionate Share of the Net OPEB Liability	Total Utility Net OPEB Liability	Utility's Covered Payroll	Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Payroll	Plan Fiduciary Net Position as a Percentage of the Total OPEB Liability
2018	2018	0.26596%	$ 33,844	$ -	$ 33,844	$ 6,907,073	0.49%	88.71%

(1) The Utility's proportionate share of the Net OPEB Liability represents the Utility's allocated portion of the Municipality's proportionate share for the given year.

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of Utility Contributions - RMP

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2018	2018	$ 31,365	$ 31,365	$ -	$ 6,969,518	0.450%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of the Utility's Information on the Net OPEB Liability - ODD

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net OPEB Liability (Asset)(1)	Utility's Proportionate Share of the Net OPEB Liability (Asset)	State of Alaska's Proportionate Share of the Net OPEB Liability (Asset)	Total Utility Net OPEB Liability (Asset)	Utility's Covered Payroll	Utility's Proportionate Share of the Net OPEB Liability as a Percentage of Payroll	Plan Fiduciary Net Position as a Percentage of the Total OPEB Liability (Asset)
2018	2018	0.26596%	$ (51,655)	$ -	$ (51,655)	$ 6,907,073	-0.75%	270.62%

(1) The Utility's proportionate share of the Net OPEB Liability (Asset) represents the Utility's allocated portion of the Municipality's proportionate share for the given year.

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Other Postemployment Benefit Plan (OPEB)
Schedule of Utility Contributions - ODD

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2018	2018	$ 11,425	$ 11,425	$ -	$ 6,969,518	0.164%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
International Brotherhood of Electrical Workers (IBEW) - Defined Benefit Pension Plan
Schedule of Utility Contributions
Last 10 Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Contractually required contribution	$ 3,382,920	3,272,545	3,396,484	3,059,562	2,642,768	2,637,978	2,778,451	2,649,741	2,560,129	2,560,894
Contributions in relation to the contractually required contribution	3,382,920	3,272,545	3,396,484	3,059,562	2,642,768	2,637,978	2,778,451	2,649,741	2,560,129	2,560,894
Contribution deficiency (excess)	$ -	-	-	-	-	-	-	-	-	-
Utility's covered payroll	$ 21,707,594	21,688,671	21,965,741	20,773,482	19,554,891	19,679,139	19,988,244	18,622,524	17,589,819	16,854,932
Contribution as a percentage of covered payroll	15.58%	15.09%	15.46%	14.73%	13.51%	13.40%	13.90%	14.23%	14.55%	15.19%

See accompanying notes to Required Supplementary Information.

(1) Public Employees Retirement System - Defined Benefit Pension Plan

In accordance with GASB Statement No. 82, "Covered Payroll" is defined as payroll on which contributions to the pension plan are based. Because a portion of the Municipality's contributions to the Plan (the DBUL) are based on Defined Contribution Wages, covered payroll reported here includes all PERS participating wages (both Defined Benefit and Defined Contribution).

Both pension tables are intended to present 10 years of information. Additional years' information will be added to the schedules as it becomes available.

Schedule of Utility's Information on the Net Pension Liability

- This table is presented based on the Plan measurement date. For December 31, 2018, the Plan measurement date is June 30, 2018.
- There were no changes in benefit terms from the prior measurement period.
- There were no changes in assumptions from the prior measurement period.
- There were no changes in valuation method from the prior measurement period.
- There were no changes in the allocation methodology from the prior measurement period. The measurement period ended June 30, 2018 allocated the net pension liability based on the present value of contributions for fiscal year 2019 through 2039, as determined by projections based on the June 30, 2017 actuarial valuation.

Schedule of Utility Contributions

- This table is based on the Utility's contributions for each year presented. A portion of these contributions are included in the plan measurement results, while a portion of the contributions are reported as a deferred outflow of resources on the December 31, 2018 statement of net position.

(2) Public Employees Retirement System - Defined Benefit OPEB Plans

In accordance with GASB Statement No. 85, "Covered Payroll" is defined as payroll on which contributions to the OPEB plan are based. Because a portion of the Utility's contributions to the Plan (the DBUL) are based on Defined Contribution Wages, covered payroll reported here includes all PERS participating wages (both Defined Benefit and Defined Contribution).

The OPEB tables are presented for each of the three PERS OPEB plans; Alaska Retiree Healthcare Trust Plan (ARHCT), Retiree Medical Plan (RMP), and Occupational Death and Disability Plan (ODD).

The OPEB tables are intended to present 10 years of information. Additional year's information will be added to the schedules as it becomes available.

Schedule of Utility's Information on the Net OPEB Liability

- These tables are presented based on the Plan measurement date. For December 31, 2018, the Plan measurement date is June 30, 2018.
- The measurement period ended June 30, 2018 allocated the net OPEB liability based on the present value of contributions for fiscal year 2019 through 2039, as determined by projections based on the June 30, 2017 actuarial valuation.

Schedule of Utility's Contributions

- These tables are based on the Utility's contributions for each year presented. A portion of these contributions are included in the plan measurement results, while a portion of the contributions are reported as a deferred outflow of resources on the December 31, 2018 statement of net position.
- All tables are intended to present 10 years' information. Additional years' information will be added to the schedule as it becomes available.

(3) International Brotherhood of Electrical Workers (IBEW) Defined Benefit Pension Plan

Schedule of Utility Contributions

- This table presents the Utility contributions for each of the last ten years based on calendar year contributions.
- In accordance with GASB Statement No. 78, "Covered Payroll" is defined as payroll on which contributions to the pension plan are based.

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STATISTICAL SECTION

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Net Position by Components
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Invested in capital assets (net of related debt)	$ 200,317,529	201,055,297	215,402,069	219,019,326	232,279,391	224,974,557	241,055,196	202,173,253	166,889,451	143,468,713
Restricted for debt service	-	71,082	269,541	802,827	590,403	1,511,334	1,550,681	33,687,889	34,582,450	34,479,471
Restricted for interim rate escrow requirement	-	-	-	-	-	-	-	-	2,048,840	-
Restricted for operations	15,206,000	14,235,000	13,200,000	12,450,000	10,100,000	9,600,000	9,600,000	10,625,000	9,400,000	8,600,000
Unrestricted	69,716,192	54,095,867	25,694,823	16,500,688	12,534,565	11,790,270	(4,131,606)	(6,887,599)	20,876,436	43,792,529
Total net position by components	$ 285,239,721	269,457,246	254,566,433	248,772,841	255,504,359	247,876,161	248,074,271	239,598,543	233,797,177	230,340,713

The Utility has prepared independent financial statements based on net position in 2014-2018. Prior to that, the Utility prepared financial statements based upon net assets from 2009-2013.
The prior years statistics have not been restated.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Change in Net Position
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Expenses:										
Production	$ 80,038,875	84,409,875	75,100,243	70,435,716	52,745,264	46,245,591	49,569,470	57,032,547	48,356,518	40,096,863
Transmission	1,206,720	1,160,932	937,495	1,010,600	1,277,246	659,063	1,146,681	551,785	517,332	560,833
Distribution	13,508,019	11,609,032	11,787,913	10,868,143	10,504,929	10,138,088	9,124,625	8,352,505	7,709,097	8,378,660
Customer service and sales	4,139,729	4,285,142	4,528,685	4,022,991	3,987,004	3,939,887	4,166,844	4,171,770	4,125,907	4,053,676
Administrative and general	9,934,148	11,044,068	11,373,116	10,689,722	11,001,466	9,590,291	9,610,553	8,808,753	8,456,134	9,446,731
Taxes other than income	894,382	1,367,440	1,737,906	986,159	981,545	988,586	849,320	610,940	548,118	363,284
Regulatory debits (credits)	(8,026,635)	(4,028,641)	6,359,769	5,923,949	(2,264,613)	(7,121,479)	(6,163,585)	3,432,854	7,556,737	4,191,550
Depreciation	28,862,200	32,453,517	31,634,639	29,643,901	30,700,970	31,184,140	26,877,295	25,948,744	26,795,802	26,250,618
Nonoperating expenses	23,136,095	22,768,624	15,507,360	17,904,982	12,900,641	11,584,587	6,980,851	11,674,152	16,093,605	10,626,438
	153,693,533	165,069,989	158,967,126	151,486,163	121,834,452	107,208,754	102,162,054	120,584,050	120,159,250	103,968,653
Operating revenues:										
Residential sales	24,180,864	26,125,850	22,260,329	21,972,135	21,435,044	18,480,248	17,221,156	18,732,524	18,576,036	17,973,827
Commercial and industrial sales	103,164,976	122,670,602	106,258,842	102,566,471	98,470,914	80,954,769	70,690,478	81,243,174	81,223,012	76,949,102
Military sales	15,021,531	17,452,871	15,437,345	14,525,488	13,422,166	11,814,277	11,827,304	15,381,907	15,687,195	13,927,149
Sales for resale	28,266,428	23,344,433	15,343,153	21,890,648	7,391,906	3,652,081	16,408,646	17,053,859	9,434,212	8,522,078
Other operating revenues	7,084,219	(5,169,343)	7,852,729	3,181,925	(812,298)	2,066,984	3,231,506	2,006,188	4,642,456	1,247,914
Operating revenues	177,718,018	184,424,413	167,152,398	164,136,667	139,907,732	116,968,359	119,379,090	134,417,652	129,562,911	118,620,070
Nonoperating revenues	3,878,498	4,868,051	3,583,438	2,936,315	3,085,196	1,851,454	3,594,606	3,938,876	5,139,469	1,778,202
Total revenues	181,596,516	189,292,464	170,735,836	167,072,982	142,992,928	118,819,813	122,973,696	138,356,528	134,702,380	120,398,272
Income before transfers	27,902,983	24,222,475	11,768,710	15,586,819	21,158,476	11,611,059	20,811,642	17,772,478	14,543,130	16,429,619
Transfer to/from other funds:										
Municipal Utility Service Assessment	(9,565,771)	(9,331,662)	(5,983,574)	(7,538,022)	(7,381,413)	(5,539,711)	(5,549,734)	(5,375,710)	(5,072,546)	(4,404,760)
Transfers to other funds	(29,418)	-	-	(8,579)	(326,886)	(250,967)	-	-	-	-
Transfers from other funds	-	-	8,456	-	-	-	-	-	-	-
Dividend	-	-	-	(7,028,943)	(5,821,979)	(6,018,491)	(6,786,180)	(6,595,402)	(6,014,120)	(5,401,356)
Total transfers	(9,595,189)	(9,331,662)	(5,975,118)	(14,575,544)	(13,530,278)	(11,809,169)	(12,335,914)	(11,971,112)	(11,086,666)	(9,806,116)
Changes in net position	$ 18,307,794	14,890,813	5,793,592	1,011,275	7,628,198	(198,110)	8,475,728	5,801,366	3,456,464	6,623,503

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Capital Assets
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Capital assets:										
Steam production	$ 242,833,584	242,833,584	242,706,892	100,399,485	100,313,798	100,499,831	27,355,731	27,255,483	26,034,220	25,696,521
Hydraulic production	8,408,752	6,932,007	5,808,598	5,808,598	5,685,191	5,575,733	5,575,733	5,540,828	5,413,702	5,284,699
Other production	309,766,612	309,370,891	302,412,281	193,263,836	185,758,015	185,638,532	143,436,524	142,440,360	136,243,299	136,017,416
Transmission plant	82,141,081	76,759,366	73,953,864	53,003,063	50,840,731	49,638,097	38,519,353	36,105,088	36,330,641	36,069,822
Distribution plant	296,099,145	280,188,291	269,997,456	261,351,063	253,135,670	244,862,546	229,933,248	219,582,019	208,302,074	197,667,947
General plant	43,929,026	43,877,572	42,912,800	42,116,790	40,586,517	38,862,644	36,182,885	33,340,550	32,923,647	30,726,421
Miscellaneous intangible plant	14,904,003	15,116,282	10,283,951	9,439,191	8,135,695	7,966,618	7,657,794	5,790,385	5,745,486	2,064,007
	998,082,203	975,077,993	948,075,842	665,382,026	644,455,617	633,044,001	488,661,268	470,054,713	450,993,069	433,526,833
Intangible plant	15,272,227	15,272,228	15,272,228	15,272,228	15,272,227	15,207,522	14,819,398	12,114,070	12,114,070	12,114,070
Other utility plant	-	-	-	-	741,167	741,167	741,167	741,167	741,167	741,167
Gas production	346,454,777	345,231,780	345,231,780	234,240,102	231,845,379	223,871,525	201,256,373	173,153,637	172,552,815	170,211,951
Total capital assets	1,359,809,207	1,335,582,001	1,308,579,850	914,894,356	892,314,390	872,864,215	705,478,206	656,063,587	636,401,121	616,594,021
Less accumulated depreciation for:										
Steam production	27,940,265	21,801,329	14,232,714	21,857,750	17,534,028	13,148,561	10,503,284	9,456,871	9,069,877	7,968,921
Hydraulic production	2,949,863	2,910,468	2,748,686	2,589,497	2,432,615	2,277,396	2,123,878	1,964,253	1,808,056	1,654,369
Other production	97,610,238	87,475,934	76,537,234	80,824,117	77,785,128	71,878,823	67,305,379	71,768,133	67,217,604	63,592,830
Transmission plant	18,669,303	17,742,318	16,586,098	15,559,845	14,866,936	14,279,448	13,555,499	12,929,380	12,668,386	12,345,716
Distribution plant	99,678,726	97,504,590	91,456,381	87,378,398	86,107,037	83,291,260	81,837,910	76,775,617	72,739,763	71,259,721
General plant	22,852,752	22,855,376	21,182,334	20,683,576	19,531,321	18,323,696	18,019,435	16,672,643	15,538,350	15,418,038
Miscellaneous intangible plant	13,670,496	11,393,594	9,850,263	8,617,566	7,270,959	5,785,215	4,406,987	3,061,171	1,909,133	997,475
	283,371,643	261,683,609	232,593,710	237,510,749	225,528,024	208,984,399	197,752,372	192,628,068	180,951,169	173,237,070
Intangible plant	12,767,052	12,661,781	12,556,509	12,253,324	11,744,249	11,235,363	10,734,809	10,300,948	9,897,146	9,493,344
Other utility plant	-	-	-	-	741,167	741,167	741,167	741,167	741,167	741,167
Gas production	201,481,664	194,387,360	182,975,820	164,257,080	146,744,614	130,649,710	116,553,669	100,919,949	88,736,800	75,095,030
Total accumulated depreciation	497,620,359	468,732,750	428,126,039	414,021,153	384,758,054	351,610,639	325,782,017	304,590,132	280,326,282	258,566,611
Total capital assets, net	862,188,848	866,849,251	880,453,811	500,873,203	507,556,336	521,253,576	379,696,189	351,473,455	356,074,839	358,027,410
Construction work in progress:										
Electric	14,830,445	22,643,309	15,783,204	258,154,569	183,164,569	71,387,105	152,887,160	104,477,262	50,665,960	20,759,469
Gas	71,840	314,131	-	151,583	1,707,078	295,199	20,418,060	31,882,134	10,281,252	2,957,087
Total construction work in progress	14,902,285	22,957,440	15,783,204	258,306,152	184,871,647	71,682,304	173,305,220	136,359,396	60,947,212	23,716,556
Total construction work in progress and net capital assets	$ 877,091,133	889,806,691	896,237,015	759,179,355	692,427,983	592,935,880	553,001,409	487,832,851	417,022,051	381,743,966

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Comparative Operating Revenue Relationships
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Residential sales:										
Average number of customers	24,699	24,680	24,678	24,555	24,429	24,463	24,443	24,302	24,206	24,139
Total kilowatt-hour sales	120,098,477	127,375,339	127,731,695	130,805,337	133,411,070	139,732,855	146,789,292	143,843,977	143,472,478	147,643,203
Total dollar revenue	$ 24,180,864	26,125,850	22,260,329	21,972,135	21,435,044	18,480,248	17,221,156	18,732,524	18,576,036	17,973,827
Average annual kilowatt-hour per customer	4,862	5,161	5,176	5,327	5,461	5,712	6,005	5,919	5,927	6,116
Average annual bill per customer	$ 979	1,059	902	895	877	755	705	771	767	745
Average revenue per kilowatt-hour sold	0.2014	0.2052	0.1743	0.1680	0.1606	0.1323	0.1173	0.1303	0.1294	0.1218
Commercial and industrial sales:										
Average number of customers	6,407	6,388	6,398	6,373	6,358	6,319	6,300	6,297	6,271	6,263
Total kilowatt-hour sales	665,319,871	688,715,880	712,231,709	722,420,813	729,977,884	742,080,706	754,621,548	753,639,798	749,946,176	760,449,972
Total dollar revenue	$ 100,074,769	119,296,069	105,104,185	101,541,955	97,502,022	80,294,932	70,118,871	80,495,645	80,415,527	76,174,620
Average annual kilowatt-hour per customer	103,843	107,814	111,321	113,356	114,813	117,436	119,781	119,682	119,590	121,419
Average annual bill per customer	$ 15,620	18,675	16,428	15,933	15,335	12,707	11,130	12,783	12,823	12,163
Average revenue per kilowatt-hour sold	0.1504	0.1732	0.1476	0.1406	0.1336	0.1082	0.0929	0.1068	0.1072	0.1002
Water diversion compensation	$ 964,797	1,248,071	1,154,656	1,024,516	968,892	659,837	571,607	747,529	807,485	774,482
Military:										
Total kilowatt-hour sales	141,657,828	144,968,449	147,440,533	146,817,935	145,055,072	160,954,213	194,549,942	209,515,273	210,847,451	203,017,515
Total dollar revenue	$ 15,021,531	17,452,871	15,437,345	14,525,488	13,422,166	11,814,277	11,827,304	15,381,907	15,687,195	13,927,149
Sales for resale:										
Total kilowatt-hour sales	476,547,000	387,688,000	213,901,000	257,893,000	94,966,698	56,954,000	157,854,000	185,375,000	121,314,000	107,788,000
Total dollar revenue	$ 28,266,428	23,344,433	15,343,153	21,890,648	7,391,906	3,652,081	16,408,646	17,053,859	9,434,212	8,522,078
Unmetered street lights:										
Total kilowatt-hour sales	4,354,949	4,430,339	4,475,018	4,452,480	4,340,094	4,702,030	4,704,154	4,643,571	4,514,322	4,853,411
Total dollar revenue	$ 2,125,410	2,126,462	1,684,211	1,662,816	1,622,449	1,348,286	1,220,224	1,258,236	1,235,236	1,211,707
Total sales:										
Total kilowatt-hour sales	1,407,978,125	1,353,178,007	1,205,779,955	1,262,389,565	1,107,750,818	1,104,423,804	1,258,518,936	1,297,017,619	1,230,094,427	1,223,752,101
Total sales revenue	$ 170,633,799	189,593,756	160,983,879	162,617,558	142,342,479	116,249,661	117,367,808	133,669,700	126,155,691	118,583,863
Average retail revenue per kilowatt-hour sold: (Residential sales and Commercial & industrial sales)										
Total dollar revenue	$ 124,255,633	145,421,919	127,364,514	123,514,090	118,937,066	98,775,180	87,340,027	99,228,169	98,991,563	94,148,447
Total kilowatt-hour sales	785,418,348	816,091,219	839,963,404	853,226,150	863,388,954	881,813,561	901,410,840	897,483,775	893,418,654	908,093,175
Average retail revenue per kilowatt-hour sold	0.1582	0.1782	0.1516	0.1448	0.1378	0.1120	0.0969	0.1106	0.1108	0.1037

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2018	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,171,443	117,988,033
Municipality of Anchorage	5,447,206	20,361,603
Fort Richardson	3,850,089	23,669,795
Anchorage School District	3,701,285	21,069,210
State of Alaska	3,318,240	23,499,108
Providence Alaska Medical	3,095,649	27,035,464
University of Alaska, Anchorage	2,395,975	17,497,854
Providence Alaska Medical	2,190,172	16,455,389
University of Alaska	2,152,954	16,221,798
Alaska Native Tribal Health Consortium	1,821,827	15,138,118

	2017	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 13,810,920	121,123,845
Municipality of Anchorage	6,244,068	21,997,754
Providence Alaska Medical	4,527,732	29,313,454
Anchorage School District	4,144,490	21,900,552
State of Alaska	4,055,188	24,489,039
Fort Richardson	3,641,951	23,844,604
University of Alaska, Anchorage	3,075,322	18,469,251
University of Alaska	2,762,581	16,788,893
Providence Health System	2,742,328	16,584,283
Alaska Native Tribal Health Consortium	2,625,088	16,570,118

	2016	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 12,249,880	121,923,613
Municipality of Anchorage	5,010,301	25,943,896
Providence Alaska Medical	4,047,395	30,672,310
State of Alaska	3,601,515	25,281,432
Anchorage School District	3,567,374	22,742,140
Fort Richardson	3,187,464	25,516,920
University of Alaska, Anchorage	2,583,129	18,519,071
University of Alaska	2,409,761	17,348,160
Providence Health System	2,384,436	17,182,319
Alaska Native Tribal Health Consortium	2,212,302	16,300,831

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2015	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,714,725	123,925,931
Municipality of Anchorage	4,906,357	26,544,546
Providence Alaska Medical	3,765,947	29,916,508
State of Alaska	3,559,141	26,353,330
Anchorage School District	3,520,203	23,392,075
Fort Richardson	2,810,763	22,892,004
University of Alaska, Anchorage	2,461,696	18,359,501
University of Alaska	2,304,264	17,427,455
Providence Health System	2,197,364	16,644,299
Alaska Native Tribal Health Consortium	2,172,315	16,242,233

	2014	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,017,465	125,613,900
Municipality of Anchorage	4,415,594	24,172,965
Providence Alaska Medical	3,530,551	29,596,430
State of Alaska	3,255,191	25,479,576
Anchorage School District	3,106,621	21,463,838
Fort Richardson	2,404,701	19,441,172
University of Alaska, Anchorage	2,177,227	17,079,887
Providence Health System	1,945,608	15,541,320
University of Alaska	1,913,342	15,008,522
Alaska Native Tribal Health Consortium	1,832,379	15,140,657

	2013	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,226,223	131,043,824
Anchorage School District	2,897,648	24,777,425
Municipality of Anchorage	3,824,941	26,282,712
State of Alaska	2,803,076	27,544,890
Providence Alaska Medical	2,629,984	28,699,997
Fort Richardson	2,588,055	29,910,389
University of Alaska	2,072,531	20,064,980
Providence Health System	1,783,576	17,591,484
Alaska Native Tribal Health Consortium	1,589,389	16,216,071
Galen Hospital Alaska, Inc	1,571,321	16,211,245

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

		2012	
Customer		Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$	8,097,877	135,878,731
Fort Richardson		3,729,428	58,671,211
Municipality of Anchorage		3,422,563	26,655,434
Anchorage School District		2,655,271	26,608,898
State of Alaska		2,492,450	28,556,399
Providence Alaska Medical		2,234,908	29,596,617
University of Alaska		1,793,961	20,506,774
Providence Health System		1,514,000	17,642,498
Galen Hospital Alaska, Inc		1,386,848	16,893,051
Alaska Native Tribal Health Consortium		1,313,019	15,929,544

		2011	
Customer		Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$	9,921,072	135,333,281
Fort Richardson		5,460,835	74,181,992
Municipality of Anchorage		3,809,602	27,353,371
Providence Alaska Medical		3,116,712	29,971,840
Anchorage School District		3,015,951	26,844,664
State of Alaska		2,752,681	26,966,050
University of Alaska		2,066,234	20,226,113
Providence Health System		1,727,491	17,114,796
Galen Hospital Alaska, Inc		1,629,192	16,791,861
Alaska Native Tribal Health Consortium		1,518,934	15,702,915

		2010	
Customer		Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$	9,991,880	134,772,525
Fort Richardson		5,695,316	76,074,926
Municipality of Anchorage		3,744,757	26,775,275
Anchorage School District		3,066,378	27,288,755
Providence Alaska Medical		2,871,643	29,775,325
State of Alaska		2,764,053	26,965,173
University of Alaska		2,042,255	19,973,125
Galen Hospital Alaska, Inc		1,655,862	16,844,949
Providence Health System		1,529,925	15,062,395
Alaska Native Tribal Health Consortium		1,428,740	14,679,960

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2009	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,053,368	132,512,540
Fort Richardson	4,873,781	70,504,975
Municipality of Anchorage	3,565,407	27,479,484
Anchorage School District	3,003,112	28,837,796
Providence Alaska Medical	2,661,493	29,740,551
State of Alaska	2,638,850	27,613,800
University of Alaska	1,942,120	20,475,951
Galen Hospital Alaska, Inc	1,573,382	17,169,527
Providence Health System	1,346,611	14,259,674
Alaska Native Tribal Health Consortium	1,296,731	14,458,413

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Summary

Effective date	Permanent 04/20/18	Interim 02/15/17	Permanent 07/16/15	Interim 10/24/13	Interim 03/01/13
Residential:					
Schedule 11					
Customer charge ($/month)	13.62	6.56	6.56	6.56	6.56
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.15274	0.14738	0.10734	0.10734	0.08634
Commercial:					
Schedule 21 - small commercial					
Customer charge ($/month)	30.46	12.88	12.88	12.88	12.88
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.11878	0.14161	0.10314	0.10314	0.08296
Schedule 22 - large commercial at secondary voltage					
Customer charge ($/month)	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW)	44.53	23.29	16.96	16.96	13.64
Energy charge ($/kWh)	0.00498	0.06630	0.04829	0.04829	0.03884
Schedule 23 - large commercial at primary voltage					
Customer charge ($/month)	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW)	43.10	26.18	19.07	19.07	15.34
Energy charge ($/kWh)	0.00488	0.06244	0.04548	0.04548	0.03658
Schedule 25 - replacement energy, AWWU					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.02561	0.03497	0.02547	0.02547	0.02049
Schedule 27 - interruptible power at secondary voltage					
Customer charge ($/month)	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.37673	0.06630	0.04829	0.04829	0.03884
Schedules 31, 32, 33 - general service seasonal at secondary voltage					
Customer charge ($/month) - winter	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW) - winter	-	-	-	-	-
Energy charge ($/kWh) - winter	0.11878	0.14161	0.10314	0.10314	0.08296
Customer charge ($/month) - summer	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW) - summer	44.53	23.29	16.96	16.96	13.64
Energy charge ($/kWh) - summer	0.00498	0.06630	0.04829	0.04829	0.03884
Schedules 34, 35, 36 - general service seasonal at primary voltage					
Customer charge ($/month) - winter	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW) - winter	-	-	-	-	-
Energy charge ($/kWh) - winter	0.09355	0.13502	0.09834	0.09834	0.07910
Customer charge ($/month) - summer	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW) - summer	43.10	26.18	19.07	19.07	15.34
Energy charge ($/kWh) - summer	0.00488	0.06244	0.04548	0.04548	0.03658
Area lighting/street lighting:					
Schedules 41/60 ($/month) (150 watt luminaire)	37.78	35.15	25.60	25.60	20.59
Schedules 42/61 ($/month) (175 watt luminaire)	39.74	36.97	26.93	26.93	21.66
Schedules 43/62 ($/month) (250 Watt luminaire)	44.81	41.70	30.37	30.37	24.43
Schedules 44/63 ($/month) (400 watt luminaire)	55.69	51.82	37.74	37.74	30.36
Schedules 45/64 ($/month) (1,000 watt luminaire)	101.61	94.55	68.86	68.86	55.39

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Summary

	Permanent	Interim	Permanent	Interim	Interim
Effective date	04/20/18	02/15/17	07/16/15	10/24/13	03/01/13
Military:					
Schedule 700 - interruptible service - Ft. Richardson - at primary voltage					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.07245	0.05368	0.03910	0.03910	0.03145
Schedule 750 - interruptible service - Elmendorf AFB - at primary voltage					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.08428	0.06244	0.04548	0.04548	0.03658
Schedule 760 - limited all requirements service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Demand charge ($/kW)	45.43	17.36	12.64	12.64	10.17
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829
Schedule 770 - partial requirements service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Baseload demand charge ($/kW)	39.66	9.44	6.87	6.87	5.53
Peaking demand charge ($/kW)	39.66	21.42	15.60	15.60	12.55
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829
Schedule 780 - seasonal replacement service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Replacement capacity charge($/kW)	39.66	9.44	6.87	6.87	5.53
Excess demand charge ($/kW)	39.66	21.42	15.60	15.60	12.55
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Typical Monthly Bill Comparison
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Residential:										
Municipal Light and Power (ML&P)	$ 106.05	115.02	94.84	91.48	88.07	72.78	63.42	71.07	70.91	67.14
Chugach Electric Association (CEA)	111.36	97.55	100.87	96.63	89.78	80.77	81.89	79.23	74.17	86.93
Matanuska Electric Association Inc. (MEA)	120.52	118.81	110.11	109.70	94.46	85.60	86.61	85.56	78.21	91.70
Homer Electric Association (HEA)	141.76	139.77	137.34	137.60	131.93	113.14	108.40	115.82	96.22	111.49
Golden Valley Electric Association (GVEA)	140.83	133.44	124.36	120.88	128.94	128.64	137.98	121.05	116.29	94.10
Small commercial:										
ML&P	234.15	280.89	231.72	223.17	214.47	176.51	153.22	172.77	172.48	162.97
CEA	232.63	198.58	207.12	199.05	187.71	170.12	177.16	170.22	157.06	198.29
MEA	285.29	286.27	269.25	268.33	229.63	207.14	209.80	207.13	188.46	222.87
HEA	338.44	333.38	327.48	328.80	314.29	266.38	254.22	273.49	224.61	263.83
GVEA	332.48	313.69	290.57	281.79	302.40	301.70	325.55	282.51	270.41	217.40
Large commercial:										
Secondary:										
ML&P	5,865.19	7,250.48	6,001.67	5,745.19	5,484.18	4,419.30	3,801.49	4,397.47	4,399.98	4,122.93
CEA	6,649.07	5,624.11	5,880.17	5,630.91	5,268.47	4,722.87	4,916.54	4,715.59	4,311.27	5,317.59
MEA	7,341.53	7,344.33	6,751.96	6,775.04	5,672.57	5,021.80	5,147.65	5,073.38	4,527.95	5,601.53
HEA	9,188.35	9,036.26	8,991.22	9,064.48	8,651.25	7,228.33	6,890.71	7,786.51	6,314.29	7,479.96
GVEA	8,619.10	8,055.39	7,365.98	7,155.64	7,814.87	7,824.12	8,588.88	7,299.38	6,967.65	5,506.23
Primary:										
ML&P	31,347.34	41,765.37	34,752.86	33,201.74	31,623.26	25,421.68	21,806.96	25,428.81	25,472.33	23,819.64
CEA	38,526.39	32,403.60	33,943.46	32,511.01	30,425.12	27,233.03	28,524.86	27,003.61	24,526.95	29,964.97
MEA	0.00	36,337.67	42,034.81	42,127.05	35,408.22	31,407.40	32,208.29	31,737.59	28,412.35	34,859.93
HEA	38,498.35	37,578.59	36,637.78	37,961.74	36,426.86	28,413.23	27,513.54	38,928.11	30,271.26	37,878.94
GVEA	50,476.56	47,067.48	42,906.03	41,735.07	45,801.46	45,927.60	50,632.17	42,919.67	38,864.16	30,500.45

Billing determinants

	Typical customer bill	
Type of service:	kWh	kW
Residential	550	n/a
Small commercial	1,400	n/a
Large commercial, secondary	42,000	100
Large commercial, primary	254,000	500

Monthly bills include customer charge, energy charge, demand charge (where applicable), cost of power adjustment (COPA), and regulatory cost charge (RCC).
At the beginning of each quarter a typical monthly bill is calculated using rates in effect for that quarter. At the end of the calendar year a simple average of the four quarters is computed and represents a typical monthly bill for the year.

Average rates are based on current typical customer bill kWh and kW. Prior years' rates have been restated to reflect a more accurate typical customer bill kWh and kW.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Comparison
Las Ten Fiscal Years

	Average in Cents/kWh*									
	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Residential:										
ML&P	19.28	20.91	17.24	16.63	16.01	13.23	11.53	12.92	12.89	12.21
CEA	20.25	17.74	18.34	17.57	16.32	14.69	14.89	14.41	13.49	15.81
MEA	21.91	21.60	20.02	19.95	17.17	15.56	15.75	15.56	14.22	16.67
HEA	25.78	25.41	24.97	25.02	23.99	20.57	19.71	21.06	17.49	20.27
GVEA	25.60	24.26	22.61	21.98	23.44	23.39	25.09	22.01	21.14	17.11
Small commercial:										
ML&P	16.72	20.06	16.55	15.94	15.32	12.61	10.94	12.34	12.32	11.64
CEA	16.62	14.18	14.79	14.22	13.41	12.15	12.65	12.16	11.22	14.16
MEA	20.38	20.45	19.23	19.17	16.40	14.80	14.99	14.80	13.46	15.92
HEA	24.17	23.81	23.39	23.49	22.45	19.03	18.16	19.53	16.04	18.84
GVEA	23.75	22.41	20.75	20.13	21.60	21.55	23.25	20.18	19.32	15.53
Large commercial:										
Secondary:										
ML&P	13.96	17.26	14.29	13.68	13.06	10.52	9.05	10.47	10.48	9.82
CEA	15.83	13.39	14.00	13.41	12.54	11.24	11.71	11.23	10.26	12.66
MEA	17.48	17.49	16.08	16.13	13.51	11.96	12.26	12.08	10.78	13.34
HEA	21.88	21.51	21.41	21.58	20.60	17.21	16.41	18.54	15.03	17.81
GVEA	20.52	19.18	17.54	17.04	18.61	18.63	20.45	17.38	16.59	13.11
Primary:										
ML&P	12.34	16.44	13.68	13.07	12.45	10.01	8.59	10.01	10.03	9.38
CEA	15.17	12.76	13.36	12.80	11.98	10.72	11.23	10.63	9.66	11.80
MEA	0.00	14.31	16.55	16.59	13.94	12.37	12.68	12.50	11.19	13.72
HEA	15.16	14.79	14.42	14.95	14.34	11.19	10.83	15.33	11.92	14.91
GVEA	19.87	18.53	16.89	16.43	18.03	18.08	19.93	16.90	15.30	12.01

Average rate comparisons, when expressed in cents per kWh, are derived by dividing the typical monthly bill by the kWh's (See Typical Monthly Bill Comparison) used to calculate the bill for each class and multiplying the result by 100 to convert to cents per kWh.

Average rates are based on current typical customer bill kWh and kW. Prior years' rates have been restated to reflect a more accurate typical customer bill kWh and kW.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)

Bond Debt

Principal and Interest (cash basis)

Year	Senior lien electric revenue bonds: Principal	Senior lien electric revenue bonds: Interest	Total
2019	$ 7,730,000	16,950,747	24,680,747
2020	8,075,000	16,603,147	24,678,147
2021	8,410,000	16,268,347	24,678,347
2022	8,760,000	15,917,897	24,677,897
2023	9,200,000	15,479,897	24,679,897
2024 - 2028	52,945,000	69,842,811	122,787,811
2029 - 2033	66,445,000	53,284,957	119,729,957
2034 - 2038	83,515,000	31,911,123	115,426,123
2039 - 2043	59,285,000	9,541,003	68,826,003
2044	11,140,000	445,600	11,585,600
	$ 315,505,000	246,245,529	561,750,529

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Schedule of Revenue Bond Coverage
Last Ten Fiscal Years

Fiscal Year	Revenue (1)(2)	Operating Expenses (3)	Net Revenue Available for Debt Service	Debt Service Requirement (accrual basis) Principal (4)	Interest (2)(4)	Total Debt Service	Coverage (5)
2018	$ 179,159,110	$ 119,287,644	$ 59,871,466	$ 7,865,000	$ 14,875,691	$ 22,740,691	***2.63***
2017	186,859,566	119,179,510	67,680,056	7,520,000	15,197,731	22,717,731	***2.98***
2016	168,290,963	117,808,701	50,482,262	7,465,000	15,561,997	23,026,997	***2.19***
2015	164,652,279	111,475,302	53,176,977	7,440,000	15,868,460	23,308,460	***2.28***
2014	140,578,329	85,614,254	54,964,075	17,910,000	10,719,674	28,629,674	***1.92***
2013	116,439,242	69,979,738	46,459,504	17,085,000	10,684,851	27,769,851	***1.67***
2012	122,973,354	73,853,642	49,119,712	16,915,000	13,953,484	30,868,484	***1.59***
2011	138,326,743	88,336,864	49,989,879	16,945,000	14,969,376	31,914,376	***1.57***
2010	134,571,665	82,342,389	52,229,276	16,995,000	15,974,962	32,969,962	***1.58***
2009	120,484,857	71,496,357	48,988,500	17,270,000	9,460,410	26,730,410	***1.83***

(1) Excludes interest charged to construction and interest restricted for construction.
(2) Excludes Federal subsidy for 2014 through 2018
(3) Includes Municipal Service Assessment per Municipal Ordinance AO 83-58 and excludes depreciation.
(4) 2014 Principal and Interest do not include the debt service for 1996 Senior Lien Bonds defeased during the year.
(5) The required minimum revenue bond coverage is 1.35 and the all-debt minimum coverage is 1.10.
Notes payable are not reflected on this schedule. If it were included, all-debt coverage for fiscal years 2018 and 2017 would be 1.70 and 1.92, respectively.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Statement of Net Position Ratios
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Current ratio	4.14	2.90	0.43	0.47	0.94	0.37	0.67	3.54	3.72	4.72

This ratio is a measure of the Utility's ability to meet short-term obligations.
The current ratio is calculated by dividing current assets by current liabilities.

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Long-term debt/gross plant	28 / 72	28 / 72	28 / 72	29 / 71	27 / 73	25 / 75	24 / 76	23 / 77	27 / 73	30 / 70

This ratio provides the gross plant value represented by long-term debt.
It is an indication of how much leverage has been utilized in acquiring plant assets.

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Debt/Equity (Net Position)	64 / 36	66 / 34	67 / 33	65 / 35	59 / 41	56 / 44	52 / 48	50 / 50	52/48	54 / 46

This ratio expresses the relationship of gross debt to net position as components of the total capital structure
(excluding net pension liability and including commercial paper).

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Return on net position (excluding dividend and speci	6.63%	5.68%	2.33%	3.15%	5.43%	2.35%	6.37%	5.30%	4.11%	5.38%

This ratio is a measure of the return received on net position.
The return on net position is calculated by dividing the change in net position, (excluding dividend and special item) by net position.

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Operating margin	26.54%	22.84%	14.17%	18.62%	22.14%	18.25%	20.27%	18.98%	19.68%	21.31%

The operating margin ratio expresses the percentage of each dollar of operating revenue that represents operating income. The ratio is calculated as operating income divided by operating revenue.

The utility started preparing independent financial statements based on net position in 2013 and based on net assets from 2007 to 2012.
The prior years have not been restated in the statistical section.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Base Ratings by Generation Units
As of December 31, 2018

		Base rating		Nameplate
Type	Unit no.	30F (MW)	ISO (MW)	capacity (KVA)
Combustion turbine	3	32.9	29.3	48,941
Combustion turbine	4	33.6	31.1	31,765
Combustion turbine	7	81.8	74.4	110,556
Combustion turbine	8	85.0	77.3	102,941
Combustion turbine	9	48.9	48.5	71,000
Combustion turbine	10	48.9	48.5	71,000
Steam turbine	11	28.9	28.9	36,000
Sub-total		360.0	338.0	472,203
Hydro-turbine (Eklutna)	1	22.2	22.2	22,222
Hydro-turbine (Eklutna)	2	22.2	22.2	22,222
Sub-total		44.4	44.4	44,444
Steam Turbine (SPP)	10	57.5	38.1	67,647
Cumbustion Turbine (SPP)	11	47.6	40.2	57,352
Cumbustion Turbine (SPP)	12	47.6	40.2	57,352
Cumbustion Turbine (SPP)	13	47.6	40.2	57,352
Sub-total		200.3	158.7	239,703
Total		604.7	541.1	756,350
ML&P units		360.0	338.0	472,203.0
Eklutna (53.3%)		23.7	23.7	23,688.7
SPP (30%)		60.1	47.6	71,910.9
		443.8	409.3	567,802.6
Plant 1		66.5	60.4	80,706
Plant 2		293.5	277.6	391,497
Eklutna		23.7	23.7	23,689
SPP		60.1	47.6	71,911

International Standards Organization (ISO)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Generated and Purchased Power (Kilowatt Hours)
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Hank Nikkels Plant 1										
Maximum generator nameplate capacity in Kilovolt Ampere (KVA)	80,706	80,706	80,706	111,956	111,956	111,956	111,956	111,956	111,956	114,750
Net peak demand on plant (kilowatts for 60 minutes)	57,000	59,000	55,000	57,000	56,000	69,000	58,000	70,000	60,000	59,000
Plant hours connected to load	1,720	3,248	2,165	2,331	1,730	1,676	2,531	3,942	2,653	3,741
Net generation kilowatt hours (kwh)	28,937,168	50,849,000	45,082,278	47,782,296	33,642,939	22,223,799	54,633,112	91,338,507	55,427,594	93,723,863
George M. Sullivan Plant 2										
Maximum generator nameplate capacity in (KVA)	213,497	213,497	213,497	291,542	291,542	291,542	291,542	291,542	291,542	291,542
Net peak demand on plant (kilowatts for 60 minutes)	99,000	100,000	144,000	162,000	116,000	147,000	182,000	201,000	210,000	208,000
Plant hours connected to load	1,417	2,733	14,771	16,841	14,594	17,166	25,062	24,856	25,837	23,511
Net generation (kwh)	62,521,710	107,834,000	589,737,560	654,788,840	493,717,440	562,282,640	1,011,487,040	1,082,362,200	1,048,416,040	1,004,741,480
Plant 2A										
Maximum generator nameplate capacity in (KVA)	178,000	178,000	178,000	-	-	-	-	-	-	-
Net peak demand on plant (kilowatts for 60 minutes)	123,000	122,000	53,000	-	-	-	-	-	-	-
Plant hours connected to load	22,792	21,646	627	-	-	-	-	-	-	-
Net generation (kwh)	781,700,477	699,634,000	16,186,000	-	-	-	-	-	-	-
Southcentral Power Plant (the Utility's entitilement is 30%)										
Maximum generator nameplate capacity in (KVA)	239,703	239,703	239,703	239,703	239,703	239,703	-	-	-	-
Net peak demand on plant (kilowatts for 60 minutes)	180,000	188,000	193,000	198,000	200,570	197,000	-	-	-	-
Plant hours connected to load	34,115	33,290	34,674	33,042	34,118	30,476	-	-	-	-
Net generation (kwh)	389,111,000	372,998,000	373,982,000	338,331,000	392,146,000	376,802,000	-	-	-	-
Eklutna Hydro Project (the Utility's entitilement is 53.33%)										
Maximum generator nameplate capacity in (KVA)	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444
Net peak demand on plant (kilowatts for 60 minutes)	40,000	40,000	40,100	43,000	41,600	41,900	41,400	41,800	41,600	41,600
Plant hours connected to load	14,179	12,020	16,964	16,510	16,525	16,975	17,092	16,460	15,083	16,597
Net generation (kwh)	168,114,718	119,916,900	168,902,714	135,428,052	156,688,891	171,456,687	144,596,206	127,446,166	129,197,695	162,284,416
The utility's actual net generation received (kwh)	67,827,000	55,029,418	69,403,457	68,552,565	83,110,070	88,671,274	71,163,019	66,107,871	74,203,136	57,058,435
Off Site Generation										
Chugach Electric Assoc. (kwh)	-	-	-	15,501,000	-	-	-	-	300,000	330,000
Purchased Power										
Alaska Energy Authority (kwh)	102,307,000	95,933,060	90,390,272	117,013,000	127,651,000	80,928,000	116,925,000	78,661,000	79,441,000	93,863,000
Chugach Electric Assoc. (kwh)	-	-	-	1,590,000	-	-	-	-	-	-

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Energy Loads and Resources
Last Ten Fiscal Years

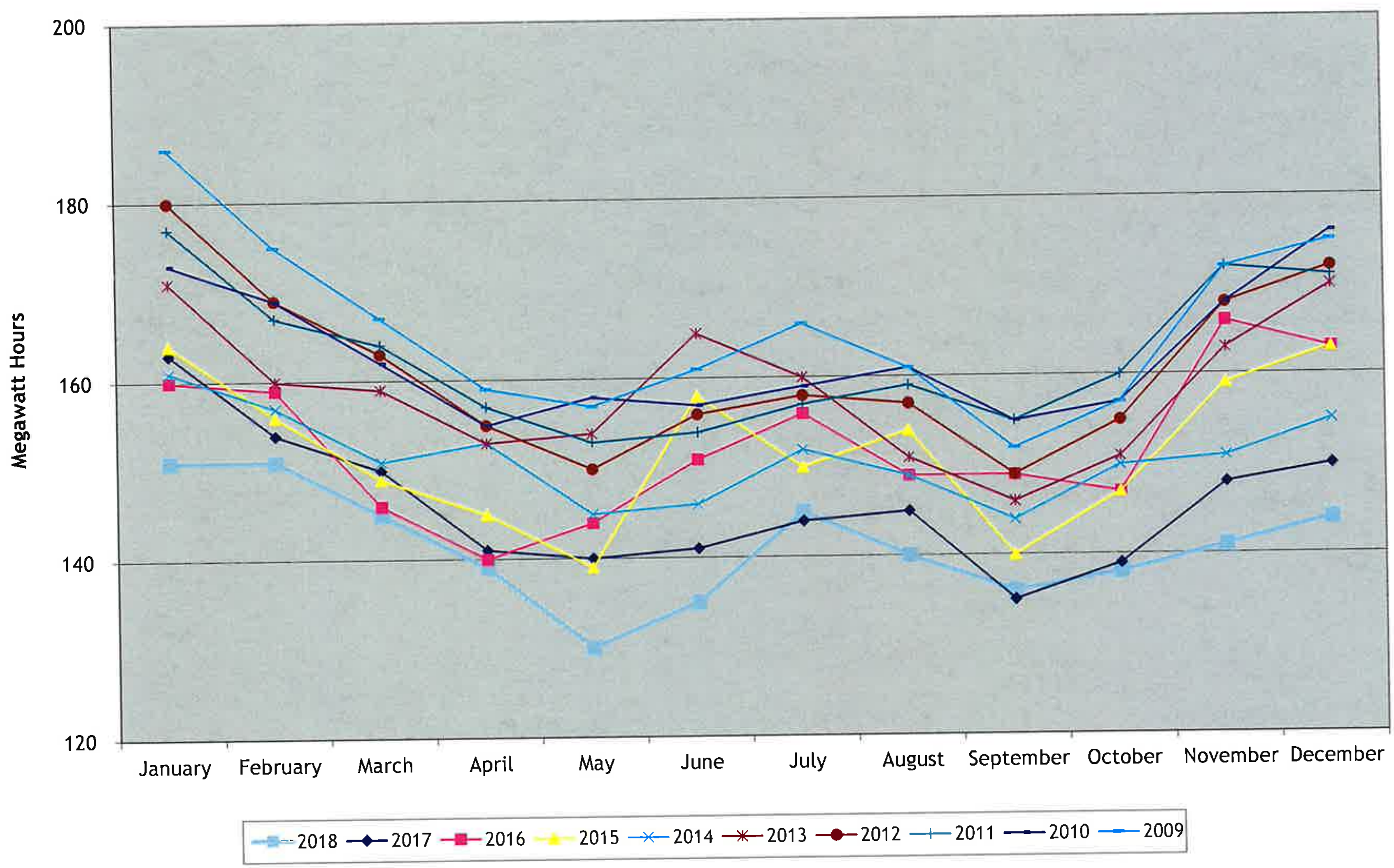
	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Sales to Customers: MWH										
Residential	120,098	127,375	127,731	130,805	133,411	139,733	146,789	143,844	143,473	147,643
Commercial	665,320	688,716	712,232	722,421	729,977	742,081	754,622	753,640	749,946	760,450
Other	146,013	149,399	151,916	151,270	149,395	165,656	199,254	214,159	215,361	207,871
Sales for Resale	476,500	387,688	213,901	257,893	94,967	56,954	157,854	185,375	121,314	107,788
Total Energy Sales	1,407,931	1,353,178	1,205,780	1,262,389	1,107,750	1,104,424	1,258,519	1,297,018	1,230,094	1,223,752
System Losses and Owner Use	58,947	59,072	50,792	50,589	38,745	46,397	36,743	43,125	49,579	45,558
Total Energy Requirements	1,466,878	1,412,250	1,256,572	1,312,978	1,146,495	1,150,821	1,295,262	1,340,143	1,279,673	1,269,310
Energy Resources:										
Own Resources	1,364,571	1,316,317	1,166,182	1,194,375	1,018,844	1,069,893	1,178,337	1,261,482	1,199,932	1,175,447
Other	102,307	95,933	90,390	118,603	127,651	80,928	116,925	78,661	79,741	93,863
Total Energy Resources	1,466,878	1,412,250	1,256,572	1,312,978	1,146,495	1,150,821	1,295,262	1,340,143	1,279,673	1,269,310

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Monthly Peak (Megawatt Hours)
Last Ten Fiscal Years

Month	Year									
	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
January	151	163	160	164	161	171	180	177	173	186
February	151	154	159	156	157	160	169	167	169	175
March	145	150	146	149	151	159	163	164	162	167
April	139	141	140	145	153	153	155	157	155	159
May	130	140	144	139	145	154	150	153	158	157
June	135	141	151	158	146	165	156	154	157	161
July	145	144	156	150	152	160	158	157	159	166
August	140	145	149	154	149	151	157	159	161	161
September	136	135	149	140	144	146	149	155	155	152
October	138	139	147	147	150	151	155	160	157	157
November	141	148	166	159	151	163	168	172	168	172
December	144	150	163	163	155	170	172	171	176	175

MUNICIPALITY OF ANCHORAGE
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)

Monthly Peak (Megawatt Hours)
Last Ten Fiscal Years



MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Miscellaneous Statistical Information
Last Ten Fiscal Years

	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Number of customers	31,112	31,074	31,081	30,932	30,751	30,767	30,747	30,603	30,481	30,406
Number of street lights	3,837	3,879	3,891	3,897	3,901	3,911	3,924	3,930	3,948	4,027
Circuit miles of overhead distribution line	114	118	118	120	122	123	124	125	130	131
Miles of underground distribution line	250	253	253	253	254	248	250	252	257	254
Plant generation capacity (30 degrees fahrenheit) - KW	424,560	424,560	444,260	395,470	395,470	395,470	364,500	364,500	364,500	366,100

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Independent Auditor's Report on Internal Control Over Financial Reporting and on Compliance and Other Matters Based on an Audit of Financial Statements Performed in Accordance With *Government Auditing Standards*

Honorable Mayor and Members of the Assembly
Municipality of Anchorage, Alaska

We have audited, in accordance with the auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the financial statements of the Electric Utility Fund, an enterprise fund of the Municipality of Anchorage, Alaska, as of and for the year ended December 31, 2018, and the related notes to the financial statements, which collectively comprise the Electric Utility Fund's basic financial statements, and have issued our report thereon dated June 30, 2019.

Internal Control Over Financial Reporting

In planning and performing our audit of the financial statements, we considered the Electric Utility Fund's internal control over financial reporting (internal control) to determine the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Electric Utility Fund's internal control. Accordingly, we do not express an opinion on the effectiveness of the Electric Utility Fund's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis. *A significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies. Given these limitations, during our audit we did not identify any deficiencies in internal control that we consider to be material weaknesses. However, material weaknesses may exist that have not been identified.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Electric Utility Fund's financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the entity's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the entity's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

BDO USA, LLP

Anchorage, Alaska
June 30, 2019

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Schedule of Findings and Responses
Year Ended December 31, 2018

Section I - Summary of Auditor's Results

Financial Statements

Type of auditor's report issued:	Unmodified	
Internal control over financial reporting:		
Material weakness(es) identified?	____ yes	X no
Significant deficiency(ies) identified?	____ yes	X (none reported)
Noncompliance material to financial statements noted?	____ yes	X no

Section II - Financial Statement Findings Required to be Reported in Accordance with *Government Auditing Standards*

There were no findings related to the financial statements which are required to be reported in accordance with the standards applicable to financial audits contained in *Government Auditing Standards*.

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Summary Schedule of Prior Year Audit Findings

Financial Statement Finding 2017-001
SAP Software Conversion – Internal Control over Financial Reporting – Material Weakness

Finding	The Electric Utility Fund did not have in place a properly functioning ERP accounting system. The Electric Utility Fund placed the SAP system into service on September 11, 2017 (payroll only) and October 1, 2017 (remainder of the system). Immediately, Management became aware of significant errors in transaction processing and financial reporting due to defects in the system. A significant number of the defects were not corrected as of year-end.
Status	Finding resolved in 2018.

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
A Major Enterprise Fund of the Municipality of Anchorage

Financial Statements,
Required Supplementary Information
and
Other Information

December 31, 2017 and 2016

(With Independent Auditor's Report Thereon)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

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3601 C Street, Suite 600
Anchorage, AK 99503

Independent Auditor's Report

Honorable Mayor and Members of the Assembly
Municipality of Anchorage, Alaska

Report on the Financial Statements

We have audited the accompanying financial statements of the Electric Utility Fund, an enterprise fund of the Municipality of Anchorage, Alaska, as of and for the year ended December 31, 2017 and 2016, and the related notes to the financial statements, which collectively comprise the Electric Utility's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements.

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes 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.

Auditor's Responsibility

Our responsibility is to express opinions on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. 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 the auditor's 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, the auditor considers internal control relevant to the entity'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 entity'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 opinions.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of the Electric Utility Fund, as of December 31, 2017 and 2016, and the respective changes in financial position and cash flows thereof for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 1, the financial statements present only the Electric Utility Fund and do not purport to, and do not, present fairly the financial position of the Municipality of Anchorage, Alaska, as of December 31, 2017 and 2016, the changes in its financial position, or where applicable, its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States. Our opinion is not modified with respect to this matter.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis on pages 4 through 15 and the Public Employees Retirement System and International Brotherhood of Electrical Workers Pension schedules on pages 61 through 66 be presented to supplement the basic financial statements. Such information, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming opinions on the financial statements that collectively comprise the Electric Utility Fund's basic financial statements. The statistical section is presented for purposes of additional analysis and are not a required part of the basic financial statements.

The statistical section has not been subjected to the auditing procedures applied in the audit of the basic financial statements, and accordingly, we do not express an opinion or provide any assurance on it.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated December 18, 2018, on our consideration of the Electric Utility Fund's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is solely to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the Electric Utility Fund's internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Electric Utility Fund's internal control over financial reporting and compliance.

BDO USA, LLP

Anchorage, Alaska
December 18, 2018

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Management's Discussion and Analysis

December 31, 2017 and 2016

The Electric Utility Fund (Utility) is a public utility of the Municipality of Anchorage (Municipality or Anchorage). The following is a discussion and analysis of the Utility's financial performance, providing an overview of the financial activities for the years ended December 31, 2017 and 2016. This discussion and analysis is designed to assist the reader in focusing on the significant financial issues, provide an overview of the Utility's financial activities and identify changes in the Utility's financial position. We encourage readers to consider the information presented here in conjunction with the Utility's financial statements and accompanying notes, taken as a whole.

Financial Highlights

- The Utility's total plant decreased $6.4 million or 0.7 % in 2017 while increasing $137.1 million or 18% in 2016. The decrease in 2017 was due to depreciation exceeding additions.
- Total assets and deferred outflows of resources exceeded total liabilities and deferred inflows of resources by $269.5 million at December 31, 2017 and by $254.6 million at December 31, 2016. Of these amounts, $54 million in 2017 and $25.7 million in 2016 were unrestricted and available to meet the Utility's ongoing obligations to customers and creditors.
- The Utility's total net position increased $14.9 million or 5.85% in 2017, compared to an increase of $5.8 million or 2.33% in 2016. The increase in net position in 2017 was primarily due to a full year of a new rate structure as well as a full year of operating Generation Plant 2A. The primary driver of increase in net position in 2016 was the restriction by the Regulatory Commission of Alaska (RCA), effective January 1, 2016, from making a revenue distribution or paying the gross receipts portion of the Municipal Service Assessment. Additionally, an increase of $11.8 million in allowance for funds used during construction (AFUDC) offset by a $9 million loss on retirement of obsolete generation assets contributed to the increase.

Overview of the Financial Statements

The Utility is a business type activity of the Municipality that provides electrical services to a specific area of the Municipality. The Utility's activities are recorded in an enterprise fund of the Municipality.

Required Financial Statements

The Utility's financial statements offer short and long-term information about the activities of the Utility and collectively provide an indication of the Utility's financial health. The basic financial statements are prepared using the economic resources measurement focus and accrual basis of accounting.

The basic financial statements, presented on a comparative basis for the years ended December 31, 2017 and 2016, include Statements of Net Position, Statements of Revenues, Expenses, and Changes in Net Position and Statements of Cash Flows.

The *Statements of Net Position* present information on all of the Utility's assets, liabilities, deferred outflows of resources and deferred inflows of resources, and provides information about the nature and amounts of investments in resources and obligations to creditors.

The *Statements of Revenues, Expenses, and Changes in Net Position* report operating and non-operating revenues and expenses, and the change in net position of the Utility for the years presented.

The *Statements of Cash Flows*, using the direct method of presentation, provide information about the Utility's cash receipts and cash payments during the years presented. These statements report cash and cash-equivalent activities for each fiscal year resulting from operating activities, noncapital financing activities, capital and related financing activities, and investing activities. These statements also provide answers to such questions as, where did cash come from, what was cash used for, and what was the change in cash balance during the reporting period.

The *Notes to Financial Statements* provide the reader with additional information that is essential to a full understanding of the data provided in the basic financial statements.

The *Required Supplementary Inform*ation presents certain information concerning the progress in funding the Utility's obligation to provide pension benefits.

Financial Analysis of the Utility

One of the most important questions asked about the Utility's finances is whether the Utility, as a whole, is better or worse off as a result of the year's activities. The Statements of Net Position and the Statements of Revenues, Expenses, and Changes in Net Position report information about the Utility's activities in ways that will help answer this question. These two statements report the net position of the Utility and changes in net position for each of the years presented. You can think of the Utility's net position, the difference between assets, deferred outflows of resources, liabilities, and deferred inflows of resources as one way to, over time, provide a measure of the Utility's financial health or financial position. Over time, increases or decreases in the Utility's net position can indicate whether its financial health is improving or deteriorating. However, you will need to also consider other non-financial factors such as changes in economic conditions and customer growth, as well as legislative and regulatory mandates.

The Utility's total net position increased $14.9 million during 2017 compared to an increase in net position of $5.8 million during 2016. The following analysis focuses on the Utility's net position and changes in net position during the year.

A portion of the Utility's net position (74.6% and 84.6% as of December 31, 2017 and 2016, respectively) reflects its investment in capital assets, such as gas and electric production, transmission and distribution facilities, less any related outstanding debt used to acquire those assets. Those capital assets are used to provide services to customers; consequently those assets are not available for future spending or to be used to liquidate any outstanding debt.

An additional portion of the Utility's net position (5.3% and 5.3% as of December 31, 2017 and 2016 respectively) represent resources that are subject to external restriction for debt repayment and future operations.

The unrestricted portion of the Utility's net position (20% and 10.1% as of December 31, 2017 and 2016, respectively) are available to be used to meet the Utility's obligations to creditors and customers.

Net Position

	December 31,		
	2017	2016	2015
Plant	$ 889,806,691	896,237,015	759,179,355
Restricted assets	108,827,334	74,769,608	138,053,331
Current and other assets	90,519,572	96,052,728	71,810,075
Deferred outflows of resources	1,372,834	3,865,199	2,270,000
Total assets and deferred outflows of resources	1,090,526,431	1,070,924,550	971,312,761
Current and other liabilities	43,479,005	228,959,153	154,293,090
Non-current liabilities	553,744,552	373,195,399	370,954,247
Deferred inflows of resources	223,845,628	214,203,565	197,292,583
Total liabilities and deferred inflows of resources	821,069,185	816,358,117	722,539,920
Net investment in capital assets	201,055,297	215,402,069	219,019,326
Restricted for debt service	71,082	269,541	802,827
Restricted for operations	14,235,000	13,200,000	12,450,000
Unrestricted	54,095,867	25,694,823	16,500,688
Total net position	$ 269,457,246	254,566,433	248,772,841

Notable components of changes in net position are discussed below.

Plant decreased $6.4 million during 2017 compared to an increase of $137.1 million during 2016.

During 2017 construction work in progress increased by $7.2 million, compared to a decrease of $242.5 million in 2016. Due to the completion of major capital projects in 2016, change in construction work in progress in 2017 is representative of a more typical year.

During 2016 construction work in progress decreased by $242.5 million, compared to an increase of $73.4 million in 2015. In both years, these changes were primarily due to ongoing construction of Generation Plant 2A and offset by increases in accumulated depreciation. In 2016, with construction substantially completed, construction costs were capitalized to plant, resulting in the decrease in construction work in progress.

Restricted assets increased $34 million during 2017 compared to a decrease of $63.3 million during 2016.

In February 2017, the RCA granted the Utility an interim and refundable rate increase of 37.30%. An interim rate escrow was established for the purpose of restricting the refundable rate increase collected from customers.

During 2016 the Utility purchased 70% of Conoco Phillips Alaska, Inc. (CPAI)'s one-third interest in the Beluga River Unit Gas field (BRU) utilizing a closing underlift settlement from CPAI and other restricted assets towards financing this acquisition. As a result of the transition to new field operators, there was very little construction in the gas field in 2016. Gas sales of $8.8 million and $1.1 million in investment earnings contributed to the activity.

Current and other assets decreased $5.5 million during 2017 compared to an increase of $24.2 million during 2016.

During 2017 the Utility's equity in general cash pool decreased by $14.7 million primarily due to the restriction of funds collected from customers pursuant to the refundable rate increase granted by the RCA. Other receivables increased by $5.8 million. Inventories of materials and supplies increased by $1.8 million primarily due to an increase in gas stored at Cook Inlet Natural Gas Storage and additional materials purchased for Plant 2A.

During 2016 the Utility's equity in general cash pool increased by $24.0 million as a result of operations. An increase of $3.0 million in utility customers receivables was offset by a decrease of $4.2 million in other receivables. Inventories of materials and supplies increased by $0.9 million.

Deferred outflows of resources decreased $2.5 million during 2017 and increased $1.6 million in 2016 as a result of changes in pension related items.

Current and other liabilities decreased $185.4 million during 2017 compared to an increase of $74.7 million during 2016.

During 2017 short-term debt decreased $181 million due to reclassification of notes payable to long-term debt. Accounts payable from restricted assets decreased $6.1 million because the Utility expended all of its proceeds from short-term debt completing Generation Plant 2A.

During 2016 short-term debt increased $66.7 million due to an increase in short-term borrowing for construction of Generation Plant 2A. Accounts payable from current assets increased $8.2 million due to additional year-end accruals, recognition of a pollution remediation liability, and over-recovery of gas costs. Accounts payable from restricted assets decreased $2.3 million due to timing differences in payments to contractors.

Non-current liabilities increased $180.5 million during 2017 compared to an increase of $2.2 million in 2016.

During 2017 the primary driver of the change was the reclassification of $191.9 million in notes payable from short-term to long-term, offset by a decrease of $2.8 million in the net pension liability and $7.5 million redemption of bonds.

During 2016 the primary driver of the change was a $6.6 million increase in the asset retirement obligation primarily due to the acquisition of CPAI's interest in the BRU, an increase in the net pension liability of $4.6 million, offset by $7.5 million redemption of bonds.

Deferred inflows of resources increased $9.6 million compared to a $16.9 million increase during 2016.

During 2017 contributions in aid of construction increased by $3.3 million due to normal fluctuations in construction on behalf of customers. Deferred inflow of resources related to pensions changed $0.8 million. The future gas sales account increased by $0.75 million in investment earnings and redemption of intercompany debt. Future BRU construction or natural gas purchases account increased by $4.8 million. There were $16.3 million in gas sales and $0.2 million in investment earnings (see Note 9 (c)).

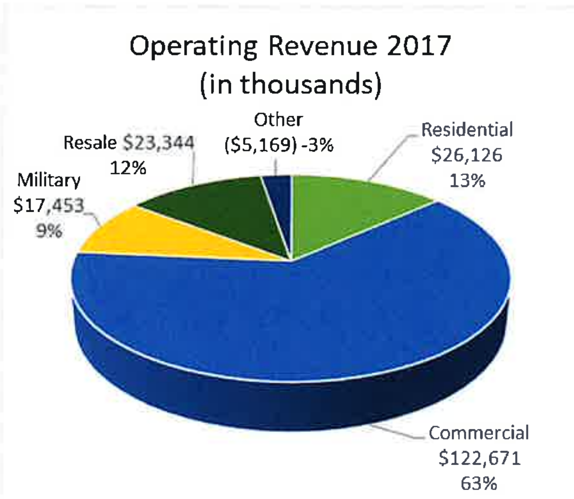
During 2016 most of the changes to deferred inflows of resources were due to the purchase of CPAI's interest in the BRU with $92.6 million in contributed capital. Contributions in aid of construction increased $85.3 million, future gas sales account decreased $17.2 million, and future BRU construction or natural gas purchases account decreased $48.7 million. There were $8.8 million in gas sales and $1.1 million in investment earnings (see Note 9 (c)).

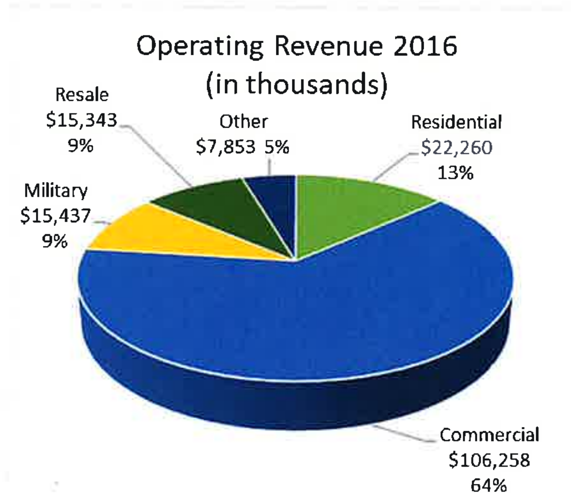
Changes in Net Position

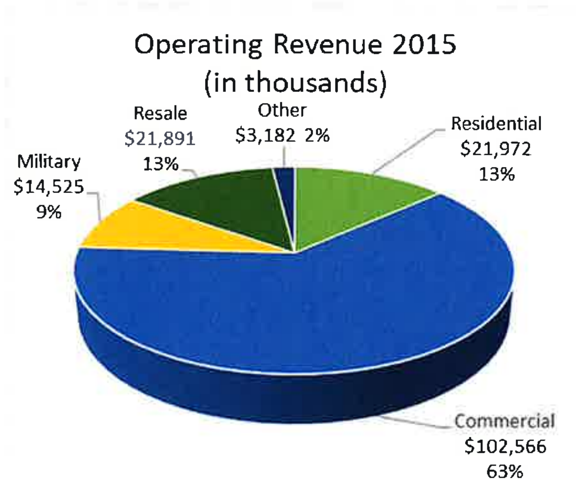
Changes in the Utility's net position can be determined by reviewing the following condensed schedule of revenues, expenses, and changes in net position for the years ended December 2017, 2016, and 2015:

	Years ended December 31,		
	2017	2016	2015
Operating revenues:			
Residential sales	$ 26,125,850	22,260,329	21,972,135
Commercial and industrial sales	122,670,602	106,258,842	102,566,471
Military sales	17,452,871	15,437,345	14,525,488
Sales for resale	23,344,433	15,343,153	21,890,648
Other operating revenues	(5,169,343)	7,852,729	3,181,925
Operating revenues	184,424,413	167,152,398	164,136,667
Nonoperating revenues	4,868,051	3,533,982	2,936,315
Total revenues	189,292,464	170,686,380	167,072,982
Expenses:			
Production	84,409,875	75,100,243	70,435,716
Transmission	1,160,932	937,495	1,010,600
Distribution	11,609,032	11,787,913	10,868,143
Customer service and sales	4,285,142	4,528,685	4,022,991
Administrative and general	11,044,068	11,373,116	10,689,722
Taxes other than income	1,367,440	1,737,906	986,159
Regulatory debits (credits)	(4,028,641)	6,359,769	5,923,949
Depreciation, net of amortization	32,453,517	31,634,639	29,643,901
Operating expenses	142,301,365	143,459,766	133,581,181
Nonoperating expenses	22,768,624	15,457,904	17,904,982
Total expenses	165,069,989	158,917,670	151,486,163
Income before transfers	24,222,475	11,768,710	15,586,819
Transfer to funds:			
Municipal Utility Service Assessment (MUSA)	(9,331,662)	(5,983,574)	(7,538,022)
Transfer (to)/from general government	-	8,456	(8,579)
Dividend	-	-	(7,028,943)
Change in net position	14,890,813	5,793,592	1,011,275
Beginning net position	254,566,433	248,772,841	247,761,566
Ending net position	$ 269,457,246	254,566,433	248,772,841

Revenues by Source:







Total revenues increased $18.6 million during 2017 compared to an increase of $3.6 million during 2016. Kilowatt hours (kWh) sold increased by 147.4 million compared to a decrease of 56.6 million in 2016. Components of the changes in revenues were:

During 2017 total operating revenues were $184.4 million, an increase of $17.3 million from 2016. The largest growth was in commercial and industrial sales, which increased $16.4 million. Increases of $3.9 million in residential sales, $2 million in military sales, and $8 million in sales for resale were offset by a decrease of $13 million in other operating revenues. Other operating revenues decreased $13 million due to over-recovery of Cost of Power Adjustment (COPA). Non-operating revenues increased by $1.3 million.

During 2016 total operating revenues were $167.1 million, an increase of $3.0 million from 2015. Military sales revenue increased by $0.9 million. Commercial and industrial sales increased by $3.7 million while sales for resale decreased by $6.5 million during the year. Other operating revenues increased by $4.6 million due to under-recovery of COPA. Non-operating revenues increased by $0.6 million.

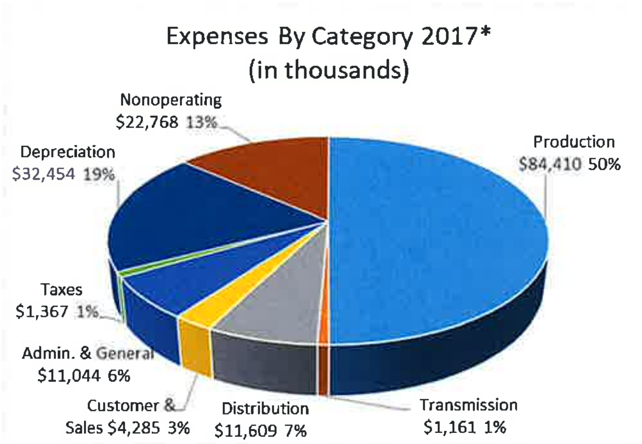
Expenses by Category

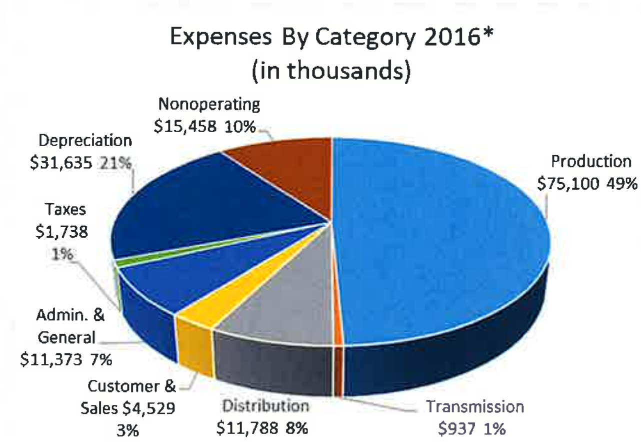
Total expenses by category increased $6.2 million during 2017 compared to an increase of $7.4 million during 2016. Components of the changes were:

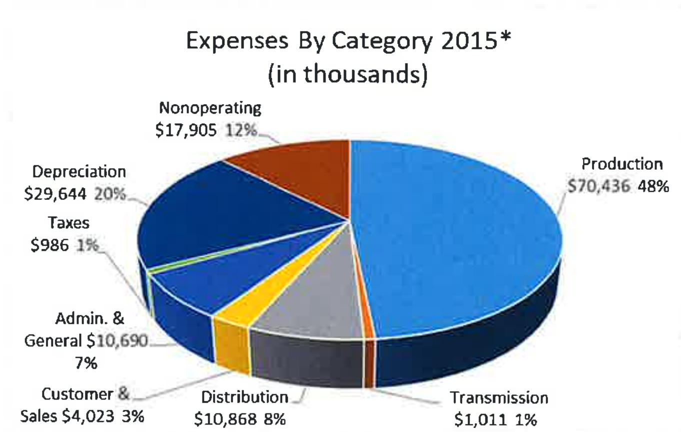
During 2017 operating expenses decreased $1.1 million from 2016, mainly due to a $9.3 million increase in production expenses offset by a $10.4 million increase in regulatory credits. Production increased mainly because more fuel was used by the Utility for increased sales of electricity for resale, and regulatory credits reflect an over-collection of COPA from customers during the year. Non-operating expenses increased $7.3 million primarily due to a $12 million decrease in AFUDC, a $0.2 million increase in interest expense on long-term obligations, and a $0.6 million increase in other interest due to an increase in interest rates, offset by a $6 million decrease in loss on disposal of property.

MUSA, which represents payments to the municipal government in lieu of property taxes, increased $3.3 million over 2016, due to the increase in plant value when Generation Plant 2A was placed in service in late 2016.

During 2016 total operating expenses increased $9.9 million from 2015 due to higher production and fuel costs, and increased depreciation expense with Generation Plant 2A being placed in service in November 2016. Gas operating expenses decreased due to the BRU joint interest ownership transition and new partners operating more efficiently. Non-operating expenses decreased $2.4 million primarily due to an $11.8 million increase in AFUDC offset by an $8.9 million loss on disposal of property. Other interest expense increased $0.78 million due to acquiring more short-term debt.





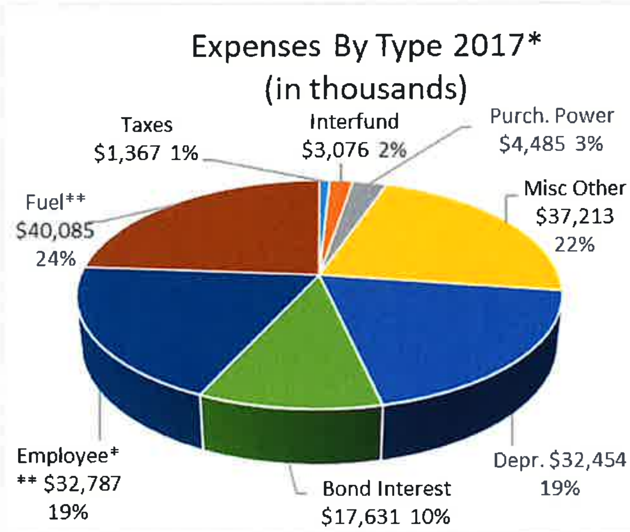


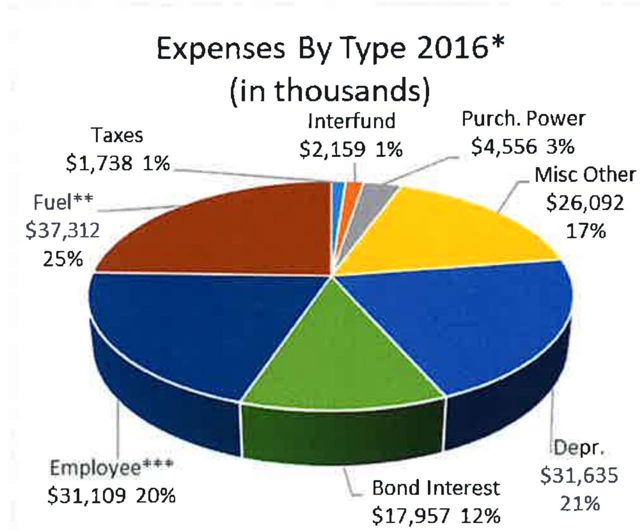
* Expenses by category excluding regulatory debits (credits)

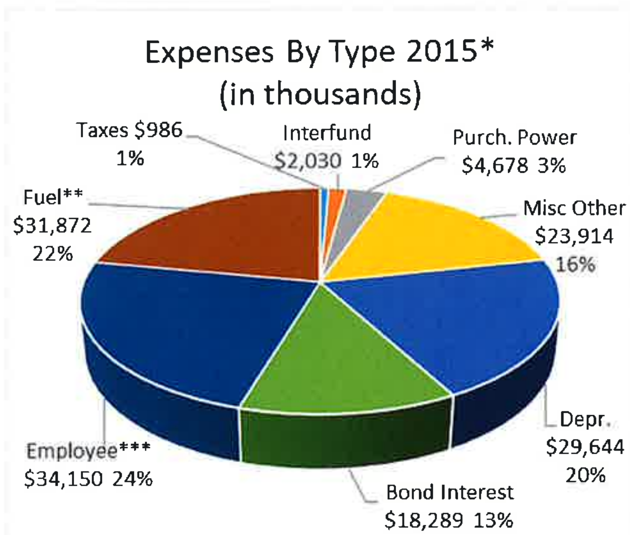
MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Management's Discussion and Analysis

December 31, 2017 and 2016







*Expenses by type excluding regulatory debits (credits)

**Fuel expense includes purchased natural gas, transportation costs, diesel fuel used, and CINGSA.

***Employee expense includes general liability and workers compensation insurance

Capital Assets - Plant

The Utility's investment in capital assets as of December 31, 2017 and 2016 was $889.8 million and $896.2 million, respectively (net of accumulated depreciation and depletion.) This included investments in gas and electric production, transmission and distribution related facilities, as well as general items such as buildings and vehicles. Plant decreased 0.72% and increased 18.1% over the prior year for 2017 and 2016, respectively. During 2013 major construction was initiated on Generation Plant 2A which continued during 2015 and 2016. Electric production assets increased while CWIP decreased due to the commissioning of Plant 2A in November 2016.

The Utility's capital assets as of December 31, 2017, 2016, and 2015 were as follows:

		2017	2016	2015
Capital assets:				
Steam production	$	242,833,584	242,706,892	100,399,485
Hydraulic production		6,932,007	5,808,598	5,808,598
Other production		309,370,891	302,412,281	193,263,836
Transmission plant		76,759,366	73,953,864	53,003,063
Distribution plant		280,188,291	269,997,456	261,351,063
General plant		43,877,572	42,912,800	42,116,790
Miscellaneous intangible plant		15,116,282	10,283,951	9,439,191
Intangible plant		15,272,228	15,272,228	15,272,228
Gas production		345,231,780	345,231,780	234,240,102
Total capital assets		1,335,582,001	1,308,579,850	914,894,356
Total accumulated depreciation		468,732,750	428,126,039	414,021,153
Total construction work in progress		22,957,440	15,783,204	258,306,152
Net capital assets	$	889,806,691	896,237,015	759,179,355

For further information regarding the Utility's plant assets, see Note 3.

Long Term Debt - Revenue Bonds

As of December 31, 2017 and 2016, the Utility had outstanding long-term debt of $533.5 million and $350.5 million, respectively.

The Utility's long term-debt as of December 31, 2017, 2016, and 2015, were as follows:

		2017	2016	2015
Revenue bonds:				
Series 2005A	$	17,565,000	22,705,000	27,780,000
Series 2009A		15,240,000	15,240,000	15,240,000
Series 2009B		114,760,000	114,760,000	114,760,000
Series 2014A		175,805,000	178,185,000	180,575,000
Unamortized discount		(476,692)	(507,779)	(539,252)
Unamortized premium		18,721,619	20,104,669	21,573,563
Total revenue bonds		341,614,927	350,486,890	359,389,311
Notes payable		191,900,000	-	-
Total long-term debt	$	533,514,927	350,486,890	359,389,311

Notes payable were reclassified from short-term to long-term in 2017. Notes payable increased $10.1 million during the year as Generation Plant 2A construction was concluded.

Bond Rating

At December 31, 2017, the Utility maintains the following underlying credit ratings:

Standard & Poor's	A+
Fitch	A+

In October 2016, Fitch reaffirmed the A+ rating of the Utility's Senior Debt.

In May 2018, Standard & Poor's reaffirmed the A+ rating of the Utility's Senior Debt.

In September 2018, Fitch reaffirmed the A+ rating of the Utility's Senior Debt.

Budgetary Highlights

On November 15, 2016, an ordinance adopting and appropriating funds for the 2017 Municipal Utilities' Operating and Capital Budgets for the Municipality was approved. The Utility's operating budget was $162,286,458 and the capital budget was $42,764,000, which includes $8.5 million for the BRU. The Utility's 2017 actual appropriated expenses of $164,629,126 were $2.3 million or 1.4% over the budget. Capital expenditures for plant improvements totaled $30 million.

On November 21, 2017, an ordinance adopting and appropriating funds for the 2018 Municipal Utilities' Operating and Capital Budgets for the Municipality was approved. The Utility's operating budget was $169,464,144 and the capital budget was $57,105,000, which includes $11 million for the BRU.

Economic Factors and Rates

Anchorage Economic Development Council's (AEDC) latest 3-year Outlook indicates Anchorage losing jobs in the first half of 2018; the expected trend is that job losses will continue to moderate, reaching a point by early 2019 where Anchorage's economy is no longer in recession. Several private entities, including Cook Inlet Housing Authority, Alaska Railroad, and Cook Inlet Region, Inc., broke ground on projects throughout our service territory. These include senior housing, affordable housing and mixed use (housing and retail). Commercial properties within our service territory include retail properties undergoing redevelopment that will expand utilization (Midtown Mall buildout of Guitar World, Carrs, and REI). Anchorage continues to see expanded tourism, which is driving the renovation of several hotel properties (La Quinta Inn & Suites, Sheraton, and Westmark Anchorage) and the construction of several new hotels (Hyatt Place Hotel and Courtyard by Marriott) within our service territory. These projects should help to offset average residential and commercial usage declines. Although some large commercial customers have expressed a desire to build co-generation or combined heat and power projects, none of these projects have moved beyond a design phase. It is expected any such project would take eighteen to twenty-four months to construct. The Utility believes plans to expand the Landfill Gas Project have been shelved based on commercial rate changes resulting from our recent rate case. JBER has suggested those changes will reverse recent trends and Fort Richardson will begin to increase electric purchases.

The Anchorage economy remains resilient with a rebound in oil prices, AEDC reported oil prices rose to $76 per barrel, the highest level since 2014. Although oil production was down a bit in 2018, the higher price per barrel generated more revenue than expected during the 2018 fiscal year. Oil companies continue to announce North Slope project investment that is expected to generate new production. Hilcorp anticipates production from their Moose Pad site in late 2018. ConocoPhillips is scheduled to bring its Greater Moose's Tooth-1 oil project online in 2018, which the company expects should provide up to 30,000 barrels of new oil per day. Additionally, leaders of the small independent Brooks Range Petroleum Corp. have said they expect to produce several thousand barrels per day of oil starting in early 2019 from their greenfield Mustang oil development. The prospect of additional oil revenue should help to reduce Alaska's budget shortfall.

Contacting the Utility's Financial Management

This financial report is designed to provide our customers, citizens, and creditors with a general overview of the Utility's finances and to demonstrate the Utility's accountability for the money it receives. If you have any questions about this report or need additional financial information, contact the Utility's Chief Financial Officer, Mollie C. Morrison, at (907) 263-5205.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Net Position

December 31, 2017 and 2016

Assets and Deferred Outflows of Resources		**2017**	**2016**
Plant:			
Plant in service, at cost	$	1,320,309,773	1,293,307,622
Less accumulated depreciation and depletion		456,070,969	415,569,530
Net plant in service		864,238,804	877,738,092
Intangible plant, net		2,610,447	2,715,719
Construction work in progress		22,957,440	15,783,204
Total plant		889,806,691	896,237,015
Restricted assets:			
Current:			
Restricted equity in general cash pool - customer deposits		1,186,226	1,170,729
Interim rate escrow investment		27,250,254	-
Bond cash investment and equity in construction cash pool		-	2,525,855
Noncurrent:			
Debt service account		2,098,515	2,098,291
Revenue bond reserve investments		23,335,229	23,143,622
Revenue bond operations and maintenance		14,235,000	13,200,000
Future natural gas purchases investment		3,811,326	1,898,732
Future BRU construction or natural gas purchases investment		23,711,907	18,934,934
Asset retirement obligation sinking fund		13,198,877	11,797,445
Total restricted assets		108,827,334	74,769,608
Current assets:			
Equity in general cash pool		32,591,181	47,336,490
Net accounts receivable:			
Utility customers, less estimated uncollectibles of $182,731 in 2017 and $132,868 in 2016		8,601,943	8,969,368
Other receivables, less estimated uncollectibles of $67,508 in 2017 and $50,533 in 2016		9,031,977	3,260,189
Accrued interest		646,359	562,555
Unbilled reimbursable projects		110,625	887,420
Inventory of materials and supplies, at average cost		32,077,195	30,261,745
Total current assets		83,059,280	91,277,767
Other assets:			
Current		3,112,503	1,627,207
Non-current:			
Unamortized regulatory assets		2,897,820	1,575,456
Unamortized debt expense		1,449,969	1,572,298
Total other assets		7,460,292	4,774,961
Total assets		1,089,153,597	1,067,059,351
Deferred outflows of resources:			
Deferred loss on refunding		248,700	516,907
Deferred outflows related to pensions		1,124,134	3,348,292
Total deferred outflows of resources		1,372,834	3,865,199
Total assets and deferred outflows of resources	$	1,090,526,431	1,070,924,550

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Net Position

December 31, 2017 and 2016

Liabilities, Deferred Inflows of Resources and Net Position	**2017**	**2016**
Current liabilities (payable from current assets):		
Notes payable	$ -	181,000,000
Accounts payable	24,493,095	23,339,311
Compensated absences payable	2,812,140	2,974,329
Accrued payroll liabilities	1,775,992	1,505,570
Accrued interest	1,688,922	1,614,313
Pollution remediation liability	511,787	760,000
Long-term obligations maturing within one year	7,865,000	7,520,000
Total current liabilities (payable from current assets)	39,146,936	218,713,523
Current liabilities (payable from restricted assets):		
Accounts payable	-	6,122,828
Customer deposits	1,186,226	1,170,729
Total current liabilities (payable from restricted assets)	1,186,226	7,293,557
Other liabilities:		
Other liabilities	3,145,843	2,952,073
Non-current liabilities:		
Notes payable	191,900,000	-
Asset retirement obligation	15,823,732	15,135,086
Net pension liability	12,270,893	15,093,423
Revenue bonds payable after one year, net of premium and discount	333,749,927	342,966,890
Total non-current liabilities	553,744,552	373,195,399
Total liabilities	597,223,557	602,154,552
Deferred inflows of resources:		
Contributions in aid of construction (net of amortization)	180,608,877	177,321,176
Future natural gas purchases	17,230,809	16,477,276
Future BRU construction or natural gas purchases	25,002,529	20,236,871
Deferred inflows related to pensions	1,003,413	168,242
Total deferred inflows of resources	223,845,628	214,203,565
Net position:		
Net investment in capital assets	201,055,297	215,402,069
Restricted for debt service	71,082	269,541
Restricted for operations	14,235,000	13,200,000
Unrestricted	54,095,867	25,694,823
Total net position	269,457,246	254,566,433
Total liabilities, deferred inflows of resources and net position	$ 1,090,526,431	1,070,924,550

See accompanying notes to basic financial statements.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Revenues, Expenses and Changes in Net Position
For the Years Ended
December 31, 2017 and 2016

	2017	2016
Operating revenues:		
Residential sales	$ 26,125,850	22,260,329
Commercial and industrial sales	122,670,602	106,258,842
Military sales	17,452,871	15,437,345
Sales for resale	23,344,433	15,343,153
Other operating revenues	(5,169,343)	7,852,729
Total operating revenues	184,424,413	167,152,398
Operating expenses:		
Production	84,409,875	75,100,243
Transmission	1,160,932	937,495
Distribution	11,609,032	11,787,913
Customer service and sales	4,285,142	4,528,685
Administrative and general	11,044,068	11,373,116
Regulatory debits (credits)	(4,028,641)	6,359,769
Taxes other than income	1,367,440	1,737,906
Depreciation, net of amortization	32,453,517	31,634,639
Total operating expenses	142,301,365	143,459,766
Total operating income	42,123,048	23,692,632
Nonoperating revenues:		
Investment income	2,098,199	821,521
Interest subsidy on Build America Bonds	2,432,899	2,395,417
PERS on Behalf	336,953	317,044
Total nonoperating revenues	4,868,051	3,533,982
Nonoperating expenses:		
Interest:		
Long-term obligations	17,104,164	16,888,535
Other interest	2,561,257	1,985,398
Total interest	19,665,421	18,873,933
Allowance for funds used during construction	(525,306)	(12,599,561)
Amortization of other assets	286,133	131,819
Loss on disposal of property	2,808,232	8,928,674
Other nonoperating expenses	534,144	123,039
Total nonoperating expenses	22,768,624	15,457,904
Total nonoperating revenues (expenses)	(17,900,573)	(11,923,922)
Income before transfers to other funds	24,222,475	11,768,710
Transfers to other funds:		
Municipal Utility Service Assessment	(9,331,662)	(5,983,574)
Transfers from general government	-	8,456
Total transfers to other funds	(9,331,662)	(5,975,118)
Change in net position	14,890,813	5,793,592
Net position - beginning of year	254,566,433	248,772,841
Net position - end of year	$ 269,457,246	254,566,433

See accompanying notes to basic financial statements.

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Cash Flows
For the Years Ended
December 31, 2017 and 2016

		2017	2016
Cash flows from operating activities:			
Receipts from customers and users	$	198,440,556	171,095,193
Other operating cash receipts		2,867,451	20,605,761
Payments to employees		(30,847,671)	(30,161,783)
Payments to vendors		(92,866,543)	(71,260,358)
Internal activity - payments made to other funds		(2,394,475)	(1,692,777)
Net cash provided by operating activities		75,199,318	88,586,036
Cash flows from noncapital financing activities:			
Transfers to other funds		(9,331,662)	(5,975,118)
Net cash used by noncapital and related financing activities		(9,331,662)	(5,975,118)
Cash flows from capital and related financing activities:			
Proceeds from issuance of short-term debt		10,900,000	66,700,000
Interest payments on short-term debt		(2,561,257)	(1,213,933)
Principal payments on long-term debt		(7,520,000)	(7,465,000)
Interest and debt issuance cost payments on long-term debt		(18,277,114)	(18,673,761)
Interest subsidy on Build America Bonds		2,432,899	2,395,417
Acquisition and construction of capital assets		(32,336,702)	(164,349,570)
Contributed capital - customers		647,401	343,884
Contributed capital - intergovernmental agencies		337,787	250,188
Payments for interfund services used		(2,200,583)	(784,745)
Proceeds from sale of property		7,934	49,456
Net cash used by capital and related financing activities		(48,569,635)	(122,748,064)
Cash flows from investing activities:			
Net (deposits to) withdrawals from restricted funds		(9,317,829)	65,683,973
Investment income received		2,014,395	852,971
Net cash provided (used) by investing activities		(7,303,434)	66,536,944
Net increase in cash		9,994,587	26,399,798
Cash, beginning of year		51,033,074	24,633,276
Cash, end of year	$	61,027,661	51,033,074
Cash and cash equivalents:			
Equity in general cash pool	$	32,591,181	47,336,490
Interim rate escrow investment		27,250,254	-
Restricted equity in general cash pool		1,186,226	1,170,729
Bond cash investment and equity in construction cash pool		-	2,525,855
Cash and cash equivalents, end of year	$	61,027,661	51,033,074

See accompanying notes to basic financial statements.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Statements of Cash Flows
For the Years Ended
December 31, 2017 and 2016

		2017	2016
Reconciliation of operating income to net cash provided by operating activities:			
Operating income	$	42,123,048	23,692,632
Adjustments to reconcile operating income to net cash provided (used) by operating activities:			
Depreciation		32,453,517	31,634,639
PERS on behalf		336,953	317,044
Allowance for uncollectible accounts		66,838	29,884
Miscellaneous nonoperating expenses		(534,144)	(123,039)
Changes in assets and liabilities which increase (decrease) cash:			
Accounts receivable		(5,471,201)	1,125,093
Unbilled reimbursable projects		776,795	21,185
Inventories		(1,815,450)	(959,810)
Other assets current		(1,485,296)	(549,391)
Other assets non-current		(1,322,364)	(73,335)
Deferred outflows of resources-related to pensions		2,224,158	(1,963,742)
Accounts payable and accrued expenses		(5,788,651)	(1,225,493)
Other liabilities		193,770	582,542
Asset retirement obligation		688,646	6,599,158
Customer deposits		15,497	(125,604)
Compensated absences payable		(162,189)	326,819
Accrued payroll liabilities		270,422	425,678
Deferred inflows of resources		14,616,328	24,286,150
Deferred inflows of resources-related to pensions		835,171	(33,789)
Net pension liability		(2,822,530)	4,599,415
Total cash provided by operating activities	$	75,199,318	88,586,036
Non-cash investing, capital and financing activities:			
Capital purchases on account	$	571,394	7,872,006
Portion of plant from AFUDC		525,306	12,599,561
Contributions in aid of construction funded from deferred inflows of resources		9,097,137	92,637,014
Total non-cash investing, capital and financing activities	$	10,193,837	113,108,581

See accompanying notes to basic financial statements

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(1) Description of Business and Summary of Significant Accounting Policies

The first electric system serving Anchorage was installed in 1916 by the Alaska Engineering Commission, the agency of the United States Department of the Interior which constructed the Alaska Railroad. A small steam plant and several diesel power generators supplied Anchorage with electricity until 1929 when the private Anchorage Power and Light Company began supplying the community with electricity from a hydroelectric power plant on the Eklutna River located 15 miles northeast of downtown Anchorage. The Alaska Engineering Commission distribution system was purchased by Anchorage in 1932. Anchorage then acquired the Eklutna plant from the Anchorage Power and Light Company in 1943. This is what is now Anchorage Municipal Light and Power or the Electric Utility Fund, a public utility of the Municipality of Anchorage. The Utility now has six turbine generating Units fired by natural gas and one heat recovery steam turbine generating Unit. The Utility also has a thirty percent ownership in Southcentral Power Project and fifty-three and one-third percent ownership interest in the Eklutna Hydroelectric Project and is entitled to twenty-five and nine-tenths percent of the output of the Bradley Lake Hydroelectric Project. The Utility meets the majority of its natural gas requirements from its ownership interest in the Beluga River Gas Field, including the initial one-third interest acquired in December 1996. The Utility's goal in acquiring the working interest in the BRU was to lock in a critical resource for the long-term and provide a hedge against anticipated future increases in natural gas prices. During 2016 the Utility acquired 70% of a one-third working interest in the field from ConocoPhillips Alaska, Inc.(CPAI), increasing its working interest to 56.67%.

The accompanying financial statements include the activities of the Utility. The Utility is an enterprise fund of the Municipality and not the Municipality as a whole. The Utility is subject to the regulatory authority of the RCA.

The Utility applies all applicable provisions of the Governmental Accounting Standards Board (GASB) which has authority for setting accounting standards for governmental entities. The accounting records of the Utility conform to the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

Accounting and reporting treatment applied to the Utility is accounted for on a flow of economic resources measurement focus using the accrual basis of accounting. Revenues are recognized when they are earned and expenses are recognized at the time liabilities are incurred. Operating revenues and expenses generally result from providing services and producing and delivering goods in connection with the Utility's principal ongoing operations. All other revenues and expenses are reported as non-operating.

(a) Regulated Operations

The Utility meets the criteria, and accordingly follows the accounting and reporting requirements applicable to regulated operations. The Utility's rates are regulated by the RCA and as a result, revenues intended to recover certain costs are provided either before or after the costs are incurred, resulting in regulatory assets or liabilities. The following regulatory assets and liabilities are reflected in the accompanying financial statements:

- The Utility receives contributions in aid of construction, which it records as contributed plant in service and a deferred inflow of resources. The Utility amortizes contributed plant and the deferred inflow of resources over the useful life of the utility plant.
- Funds from a settlement for 2005 BRU underlift were deposited in the Future Gas Purchases Fund. On April 21, 2016 the Utility received permission from the RCA to use a portion of these funds toward its purchase of 70% of the one-third BRU interest then-owned by CPAI. See Notes 9(a) and (f).
- The Utility accepted a monetary settlement in 2015 from its BRU partners for its 2014 underlift. The Utility is utilizing these funds to reduce its Gas Transfer Price (GTP) from July 1, 2016 through June 30, 2017. See Note 9(a).
- The Utility accepted a monetary settlement in 2016 from CPAI for cumulative underlift. These funds financed, in part, the Utility's 70% purchase of CPAI's BRU interest. See Notes 9(a) and (f).
- The Utility has a regulatory asset or liability account to capture the difference in the cost of power and revenue received through the Cost of Power Adjustment (COPA). See Note 9(b).
- The Utility has a regulatory asset or liability account to capture the difference in the amount of the Gas Fund revenue requirement and the actual amount of revenue collected from the Electric Fund. See Note 9(b).
- The Utility records proceeds from the sales of gas, net of royalties, taxes and an Asset Retirement Obligation (ARO) surcharge, as a deferred regulatory liability. See Note 9(c).
- The Utility funds ARO expenses associated with future abandonment of the BRU through a surcharge to the Utility's GTP, which is deposited into a sinking fund. See Note 9(c) and (d).

Management believes that the recorded amounts of all regulatory assets are fully recoverable from ratepayers in the future.

(b) Management Estimates

In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and deferred outflows of resources, liabilities and deferred inflows of resources and the reporting of contingent assets and liabilities as of the date of the statement of net position and revenues and expenses for the period. Actual results could differ from those estimates. The more significant accounting and reporting policies and estimates applied in the preparation of the accompanying financial statements are discussed below.

(c) Cash Pools and Investments

The Municipality uses a central treasury to account for all cash and investments to maximize interest. Interest income on cash pool investments is distributed based on the average daily balance in the general cash pool. The Utility's investments are reported at fair value in the financial statements.

(d) *Statements of Cash Flows*

For purposes of the statements of cash flows, the Utility has defined cash as the demand deposits and all investments maintained in the general and construction cash pool, regardless of maturity period, since the Utility uses the cash pools essentially as demand deposit accounts. Restricted assets in the general cash pool, except for revenue bond proceeds and customer deposits, have not been included in the definition of cash.

(e) *Restricted Assets*

Certain proceeds of the Utility's revenue bonds, as well as resources set aside for their repayment, are classified as restricted assets on the statements of net position because their use is limited by applicable bond covenants. The revenue bond reserve investments account is used to report resources set aside to augment potential deficiencies from Utility operations that could adversely affect debt service payments. The debt service account is used to segregate resources accumulated for debt service payments over the next twelve months. The revenue bond operations and maintenance account represents funds set aside to comply with bond covenants requiring a reserve equal to one-eighth of the preceding year's operating expenses (as defined in the bond covenants).

The restricted equity in general cash pool-customer deposits account represents deposits provided by electric service customers as security for bill payment. Equity in the bond cash investment and equity in the construction cash pool is the cash restricted for construction by bond covenants. Future natural gas purchases or BRU construction and ARO sinking funds are funds for which the RCA has specified the use.

Interim revenue escrow investments are funds collected from customer sales arising from interim and refundable rates granted by the RCA. The restriction on those funds was lifted on June 1, 2018 by the RCA following the submittal of tariff sheets in compliance with RCA Order No. 13 in U-17-008. (See Note 9(e).)

(f) *Inventories*

Inventories are valued at weighted average cost. The cost of inventories are recorded as expenditures when consumed rather than when purchased. Inventories consist of parts and materials used to maintain or build new transmission, distribution, and generation facilities. Scrap and nonusable materials in inventory are carried at net estimated realizable value until sold or otherwise disposed of.

The Utility also stores natural gas in a depleted field on the Kenai Peninsula. Cook Inlet Natural Gas Storage Alaska (CINGSA) started in 2012 and as of December 31, 2017 the Utility has stored 3.86 billion cubic feet of gas.

(g) Property, Plant and Equipment

Electric

Capital assets are stated at cost. Depreciation is computed by use of the straight-line method over the estimated economic life of the asset. Additions to electric plant in service are at original cost of items such as contracted services, direct labor and materials, indirect overhead charges and AFUDC. The Utility capitalizes general plant assets valued at more than $25,000 that have an expected life in excess of one year. Contributed assets are recorded at the cost incurred by the Utility for the addition of such assets. Donated assets are recorded at acquisition value. Acquisition value is the price that would be paid to acquire an asset with equivalent service potential in an orderly market transaction at the acquisition date. For property replaced or retired, the cost of the property unit, plus removal costs less salvage, is charged to accumulated depreciation. Gain or loss is not recognized unless the Utility determines that such costs could not be recovered in rates. Costs for maintenance and repairs are expensed as incurred, except for major maintenance on generation assets, for which costs are collected into a regulatory asset and amortized over the period of utility, generally three to five years.

Estimated lives of major plant and equipment categories follow:

Production plant	24 - 60 years
Hydraulic plant	40 - 45 years
Transmission plant	45 - 60 years
Distribution plant	17 - 55 years
General plant - buildings	40 - 60 years
Vehicles	16 - 20 years
Other general plant	5 - 20 years
Plant acquisition	23 years
Intangible plant	5 - 30 years

Gas

Acquisition costs, the costs of wells, related equipment and facilities initially acquired as part of the 1996 acquisition of a one-third working interest in the BRU are, as a result of a regulatory proceeding and subsequent order by the RCA, being depleted at 125% of the principal payments on the debt used to finance the acquisition of this asset.

The acquisition of assets purchased with designated underlift settlement funds are being amortized using the units of production method, based upon proven reserves in accordance with the amortization method used for regulatory purposes. The acquisition of assets purchased with gas sale proceeds, and assets acquired from CPAI in the 2016 purchase, are being recorded as contributed plant and are being amortized using the units of production method, based on proven reserves in accordance with the amortization method used for regulatory purposes.

(h) Unbilled Revenues and Accounts Receivable

Electric revenues are based on cycle billings rendered to customers monthly. As a result of this cycle billing method, the Utility does not accrue revenue at the end of any fiscal period for services sold but not billed at such date. The unbilled revenues for the Utility are immaterial. An allowance for doubtful accounts is provided for receivables where there is a question of collectability. Utility receivables are presented in the statements of net position net of estimated uncollectible amounts.

Gas sales are calculated based upon volumes delivered and recorded as a regulatory liability/deferred inflows of resources (see Note 9(c))

(i) Gas Balancing

The Utility has elected to account for underlifted gas from its ownership interest in the BRU according to the sales method. Therefore, the financial statements do not include a receivable or revenue for underlifted volumes for which the Utility did not elect to receive cash settlement. The Utility had an accumulated underlift balance at the end of 2007 for which the Utility did not accept monetary settlement of 15,127,694 thousand cubic feet (Mcf). Between year-end 2007 and 2015, the underlift balance was reduced to 2,751,091 Mcf. During 2016, the Utility further reduced the underlift balance pursuant to the purchase and sale agreement for the acquisition of CPAI's one-third interest in the BRU (See Notes 9(a) and (f)). As of December 31, 2017, the underlift balance was 172 Mcf. The Utility also has the option per the Gas Balancing Agreement to take cash settlements for any underlifted gas.

(j) Asset Retirement Obligation

The Utility accounts for its ARO for its interest in the BRU in accordance with Accounting Standards Codification (ASC) Topic #410-20, formerly Statement of Financial Accounting Standards No 143, *"Accounting for Asset Retirement Obligations" (SFAS No 143)* and 18 CFR 101 General Instruction No 25, *Accounting for Asset Retirement Obligations (Regulations of the Federal Energy Regulatory Commission, Department of Energy, or FERC)*. ASC 410-20 and FERC General Instruction No 25 applies to the fair value of a liability for an ARO that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated.

Obligations associated with the retirement of these assets require recognition of: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

In 2012 the Utility made its initial recording of the ARO asset and ARO liability with a beginning balance of $1,461,335 representing the fair value of the obligation at 1996 - the period when the obligation was incurred. The Utility recorded in 2012 $4,185,549 to the ARO liability representing total accretion expense that would have been incurred if the liability was accreted from the time the obligation was incurred through December 31, 2012. During 2013, the Utility commissioned a study of the costs associated with abandoning the BRU field and as a result of the findings of that study, adjusted the ARO liability and accretion as of December 2013. On April 22, 2016, the Utility purchased 70% of CPAI's one-third interest in the BRU. At that time a revised estimate was made of the life of the gas field. The Utility's obligation for an ARO was adjusted for the increased liability and changes in estimated life and discount rate.

As of December 31, 2016, the Utility entered into an agreement with the State of Alaska Department of Natural Resources (DNR) to establish an ARO investment fund to meet its obligations for dismantling, removing and restoring the land and property to a condition acceptable to the commissioner of the DNR in accordance with the terms and conditions of assigned leases and applicable statutes and regulations.

A schedule of changes in the ARO balance for the years ending December 31, 2017 and 2016 is as follows:

		2017	2016
Asset to be retired:		Gas Field	
Beginning carrying value	$	15,135,086	8,535,928
Current year changes to the liability balance		-	5,996,423
Current year settled		-	-
Current year accretion		688,646	123,778
Change in assumption or cash flow revisions		-	478,957
Ending ARO	$	15,823,732	15,135,086

(k) *Discount or Premium on Revenue Bonds Payable*

The discount or premium on revenue bonds payable is amortized over the life of the related bond issues using the effective interest method.

(l) *Compensated Absences*

The Utility records employee leave, which includes sick leave, when earned.

(m) *Deferred Outflows and Inflows of Resources*

The Utility enters into transactions that result in the consumption or acquisition of net assets in one period that are applicable to future periods. These consumptions and acquisitions of net assets are reported in the statement of net position as deferred outflows and inflows of resources, respectively. The Utility records deferred outflows of resources related to pensions and deferred loss on refunding of bonds, and deferred inflows of resources related to pensions, contributions in aid of construction and certain items related to the operation of the BRU.

(n) *Net Position*

The Utility's net position is categorized as net investment in capital assets, restricted or unrestricted. The Utility's restricted net position represents assets restricted for payment of debt service, or restricted for operations, in accordance with covenants of the related revenue bond indentures.

(o) *Intragovernmental Charges*

Certain functions of the Municipality of a general and administrative nature are centralized and the related costs are allocated to the various funds of the Municipality, including the Utility. Such costs allocated to the Utility totaled $3,580,714 and $2,610,507 for the years ended

December 31, 2017 and 2016, respectively, including general liability and workers compensation of $504,452 for 2017 and $450,845 for 2016.

(p) *Utility Revenue Distribution/Municipal Service Assessment (MUSA)*

Prior to 2006, the RCA restricted the Utility from making a revenue distribution or paying the gross receipts portion of the MUSA. That restriction was removed in December 2005. The Utility made an annual revenue distribution to the Municipality for the years 2006 - 2015, which by Ordinance, was up to a maximum of 5% of the Utility's gross revenues, excluding restricted revenues. During those years the Utility also included the gross receipts portion, considered supplemental MUSA, at 1.25% times the actual gross operating revenues in its payment of MUSA.

As of January 1, 2016, the Utility is restricted by the RCA from making a revenue distribution or paying the gross receipts portion of the MUSA. The Utility's distribution for MUSA in 2017 and 2016 was $9,331,662 and $5,983,574, respectively.

(q) *Risk Management and Self-Insurance*

The Municipality is exposed to various risks of loss related to torts; theft of, damage to and destruction of assets; errors and omissions; illness of and injuries to employees; unemployment; and natural disasters. The Municipality utilizes three risk management funds to account for and finance its uninsured risks of loss.

The Municipality provides coverage up to the maximum of $3,000,000 per occurrence for automobile and general liability claims and for each workers' compensation claim. No settled claim exceeded this commercial coverage in 2017, 2016 or 2015.

Unemployment compensation expense is based on actual claims paid by the State of Alaska and reimbursed by the Municipality.

All Municipal departments participate in the risk management program and make payments to the risk management funds based on actuarial estimates of the amounts needed to pay prior and current year claims.

Claims payable represent estimates of claims to be paid based upon past experience modified for current trends and information. The ultimate amount of losses incurred through December 31, 2017, is dependent upon future developments. At December 31, 2017, claims incurred but not reported for the Municipality as a whole included in the liability accounts are $12,008,623 in the General Liability/Workers' Compensation Fund and Medical/Dental Self Insurance Fund.

(r) *Environmental*

The Utility has adopted an aggressive policy designed to identify and mitigate the potential effects of past, present, and future operational activities that may result in environmental impact. It is the Utility's accounting policy to record a liability when the likelihood of responsibility for an environmental impact is probable and the cost of mitigating the impact is estimable within reasonable limits. Such costs are capitalized if they result in an extension of the assets' life, increase the capacity, or improve the safety or efficiency of property owned by the Utility; or mitigate or prevent environmental contamination that has yet to occur and that otherwise may result from future operations or activities. At December 31, 2016, the Utility recorded a liability of $760,000 for environmental cleanup responsibilities related to a capital project at Hank Nikkels Power Plant 1. At December 31, 2017, the liability remained at $511,787. See note 7(a). There were no other environmental issues that met the Utility's accounting policy and accordingly, no provision has been made in the accompanying financial statements for any potential liability.

(s) *Reclassifications*

Certain amounts previously reported may have been reclassified to conform with the current presentations. The reclassifications had no effect on previously reported change in net position.

(2) Cash and Investments

At December 31, 2017 and 2016, the Municipality had cash and investments in a general cash pool (Central Treasury). The Utility also carries certain balances, beginning in 2017, in separate accounts for Interim Rate Increase Escrow and Asset Retirement Obligations. Fixed income maturities for these accounts are as follows:

December 31, 2017

		Fixed Income Investment Maturities (in years)			
Investment Type	Fair Value*	Less Than 1	1 - 5	6 - 10	More Than 10
Petty Cash	**$ 1,000**				
Interim Rate Increase Escrow - Money Market	**27,250,254**				
Central Treasury - Restricted					
Cash & Money Market Funds	37,673,284	-	-	-	-
Commercial Paper	1,535,603	1,535,603	-	-	-
U.S. Treasuries	121,706,339	13,506,923	87,014,400	21,185,016	-
U.S. Agencies	13,180,799	550,253	241,092	6,981,798	5,407,656
Asset-Backed Securities**	34,730,718	(1,065,202)	23,333,226	4,460,439	8,002,255
Corporate Securities	122,048,793	14,372,805	59,766,782	43,625,370	4,283,836
	$ 330,875,536	$ 28,900,382	$ 170,355,500	$ 76,252,623	$ 17,693,747
Central Treasury - Unrestricted					
Cash & Money Market Funds	$ 32,165,339	$ -	$ -	$ -	$ -
Commercial Paper	99,654	99,654	-	-	-
U.S. Treasuries	22,840,772	15,819,079	5,646,873	1,374,820	-
U.S. Agencies	21,909,848	4,118,857	16,986,967	453,090	350,934
Asset-Backed Securities**	2,253,879	(69,127)	1,514,229	289,464	519,313
Corporate Fixed Income Securities	7,920,460	932,735	3,878,616	2,831,105	278,004
	$ 87,189,952	$ 20,901,198	$ 28,026,685	$ 4,948,479	$ 1,148,251
Total Central Treasury	$ 418,065,488	$ 49,801,580	$ 198,382,185	$ 81,201,102	$ 18,841,998
Utility share of Central Treasury	**$ 77,632,813**				
Asset Retirement Obligation Fund					
Cash & Money Market Funds	$ 456,333	$ -	$ -	$ -	$ -
U.S. Fixed Income	8,220,807	-	2,352,657	3,622,444	2,245,706
U.S. TIPS	942,226	-	942,226	-	-
U.S. Large-Cap Equity	1,751,027	-	-	-	-
U.S. Mid-Cap Equity	265,692	-	-	-	-
U.S. Small-Cap Equity	261,154	-	-	-	-
International Developed Equity	657,596	-	-	-	-
Emerging Markets Equity	133,715	-	-	-	-
Real Estate	510,327	-	-	-	-
	$ 13,198,877	$ -	$ 3,294,883	$ 3,622,444	$ 2,245,706
Total Utility	**$ 141,418,515**				

* Market value plus accrued income.

** Includes asset-backed securities, residential and commercial mortgage-backed securities, and collateralized debt obligations.

December 31, 2016

Investment Type		Fair Value*	Fixed Income Investment Maturities (in years) Less Than 1	1 - 5	6 - 10	More Than 10
Petty Cash	**$**	**1,000**				
Central Treasury - Restricted						
Cash & Money Market Funds		47,692,839	-	-	-	-
Repurchase Agreements		2,902,556	2,902,556	-	-	-
Commercial Paper		299,827	299,827	-	-	-
Certificates of Deposit		240,900	240,900	-	-	-
U.S. Treasuries		13,307,427	4,282,430	7,879,780	1,145,217	-
U.S. Agencies		39,384,533	20,020,719	18,380,009	500,338	483,467
Municipal Bonds		19,726	-	-	19,726	-
Asset-Backed Securities		3,944,233	83,298	2,604,572	591,869	664,493
Corporate Fixed Income Securities		16,708,812	6,771,159	5,691,704	3,973,028	272,921
	$	124,500,853	$ 34,600,889	$ 34,556,065	$ 6,230,178	$ 1,420,881
Central Treasury - Unrestricted						
Cash & Money Market Funds		6,556,270	-	-	-	-
Repurchase Agreements		34,032,002	34,032,002	-	-	-
Commercial Paper		3,515,419	3,515,419	-	-	-
Certificates of Deposit		2,824,520	2,824,520	-	-	-
U.S. Treasuries		123,312,501	17,495,823	92,389,185	13,427,493	-
U.S. Agencies		66,705,430	54,756,761	413,700	5,866,387	5,668,582
Municipal Bonds		231,288	-	-	231,288	-
Asset-Backed Securities		46,245,507	976,652	30,538,202	6,939,573	7,791,080
Corporate Fixed Income Securities		137,193,556	20,676,137	66,734,333	46,583,129	3,199,957
	$	420,616,493	$ 134,277,314	$ 190,075,420	$ 73,047,870	$ 16,659,619
Utility share of Central Treasury	**$**	**122,105,098**				
Total Utility	**$**	**122,106,098**				

Reported in the Statement of Net Position:

	2017	2016
Restricted assets:		
Customer deposits	$ 1,186,226	$ 1,170,729
Revenue bond operations and maintenance	14,235,000	13,200,000
Debt service account	2,098,515	2,098,291
Bond cash investment and equity in construction cash pool	-	2,525,855
Future natural gas purchases investment	3,811,326	1,898,732
Future BRU construction or natural gas purchases investment	23,711,907	18,934,934
Interim rate escrow investment	27,250,254	-
Asset retirement obligation sinking fund	13,198,877	11,797,445
Revenue bond reserve investments	23,335,229	23,143,622
Total restricted assets:	108,827,334	74,769,608
Unrestricted equity in general cash pool	32,590,181	47,335,490
Petty cash	1,000	1,000
Total Utility cash and investments	$ 141,418,515	$ 122,106,098

(a) Municipal Central Treasury

The Municipality manages its Central Treasury in four portfolios; one internally managed portfolio and three externally managed duration portfolios based on liability duration and cash needs: working capital, contingency reserve and strategic reserve.

The Municipality maintains a comprehensive policy over cash and investments that is designed to mitigate risks while maximizing investment return and providing for operating liquidity. Pursuant to Anchorage Municipal Code (AMC) 6.50.030, the Municipality requires investments to meet specific rating and issuer requirements.

Both externally and internally managed investments are subject to the primary investment objectives outlined in AMC 6.50.030, in priority order as follows: safety of principal, liquidity, return on investment and duration matching. Consistent with these objectives, AMC 6.50.030 authorizes investments that meet the following rating and issuer requirements:

- Obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government sponsored corporations and agencies.
- Corporate Debt Securities that are guaranteed by the U.S. government or the Federal Deposit Insurance Corporation (FDIC) as to principal and interest.
- Taxable and tax-exempt municipal securities having a long-term rating of at least A- by a nationally recognized rating agency or taxable or tax-exempt municipal securities having a short-term rating of at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch.
- Debt securities issued and guaranteed by the International Bank for Reconstruction and Development (IBRD) and rated AAA by a nationally recognized rating agency.
- Commercial paper, excluding asset-backed commercial paper, rated at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch.
- Bank debt obligations, including unsecured certificates of deposit, notes, time deposits, and bankers' acceptances (with maturities of not more than 365 days), and deposits with any bank, the short-term obligations of which are rated at least A-1 by Standard & Poor's, P-1 by Moody's, or F-1 by Fitch and which is either:

    a) Incorporated under the laws of the United States of America, or any state thereof, and subject to supervision and examination by federal or state banking authorities; or
    b) Issued through a foreign bank with a branch or agency licensed under the laws of the United States of America, or any state thereof, or under the laws of a country with a Standard & Poor's sovereign rating of AAA, or a Moody's sovereign rating for bank deposits of Aaa, or a Fitch national rating of AAA, and subject to supervision and examination by federal or state banking authorities.

- Repurchase agreements secured by obligations of the U.S. government, U.S. agencies, or U.S. government-sponsored corporations and agencies.

- Dollar denominated corporate debt instruments rated BBB- or better (investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.
- Dollar denominated corporate debt instruments rated lower than BBB- (non-investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.
- Dollar denominated debt instruments of foreign governments rated BBB- or better (investment grade) by Standard & Poor's or the equivalent by another nationally recognized rating agency.
- Asset Backed Securities (ABS), excluding commercial paper, collateralized by: credit cards, automobile loans, leases and other receivables which must have a credit rating of AA- or above by Standard & Poor's or the equivalent by another nationally recognized rating agency.
- Mortgage Backed Securities, including generic mortgage-backed pass-through securities issued by Ginnie Mae, Freddie Mac, and Fannie Mae, as well as non-agency mortgage-backed securities, Collateralized Mortgage Obligations (CMOs), or Commercial Mortgage-Backed Securities (CMBS), which must have a credit rating of AA- or better by Standard & Poor's or the equivalent by another nationally recognized rating agency.
- Debt issued by the Tennessee Valley Authority
- Money Market Mutual Funds rated Am or better by Standard & Poor's, or the equivalent by another nationally recognized rating agency, as long as they consist of allowable securities as outlined above.
- The Alaska Municipal League Investment Pool (AMLIP).
- Mutual Funds consisting of allowable securities as outlined above.
- Interfund Loans from a Municipal Cash Pool to a Municipal Fund.

In addition to providing a list of authorized investments, AMC 06.50.030 specifically prohibits investment in the following:

- Structured Investment Vehicles.
- Asset Backed Commercial Paper.
- Short Sales.
- Securities not denominated in U.S. Dollars.
- Commodities.
- Real Estate Investments.
- Derivatives, except "to be announced" forward mortgage-backed securities (TBAs) and derivatives for which payment is guaranteed by the U.S. government or an agency thereof.

The Investment Management Agreement (IMA) for each external manager and the policy and procedures (P&P) applicable to the internally managed investments provide additional guidelines for each portfolio's investment mandate. The IMA and P&P limit the concentration of investments for the working capital portfolio and the internally managed portfolio at the time new investments are purchased as follows:

Investment Type	Concentration Limit	Working Capital Portfolio Holding % at December 31, 2017	Internally Managed Holding % at December 31, 2017
U.S. Government Securities*	50% to 100% of investment portfolio	28%	55%
Repurchase Agreements	0% to 50% of investment portfolio	0%	0%
Certificates of Deposit	0% to 25% of investment portfolio Maximum 5% per issuer	0%	0%
Bankers Acceptances	0% to 25% of investment portfolio Maximum 5% per issuer	0%	0%
Commercial Paper	0% to 25% of investment portfolio Maximum 5% per issuer	2%	0%
Corporate Fixed Income**	0% to 25% of investment portfolio Maximum 5% per issuer	11%	0%
Alaska Municipal League Investment Pool (AMLIP)***	0% to 25% of investment portfolio	0%	0%
Money Market Mutual Funds****	0% to 25% of investment portfolio	59%	45%
Dollar Denominated Fixed Income Securities, other than those listed herein, rated by at least one nationally recognized rating agency	0% to 15% of investment portfolio Maximum 5% per issuer	0%	0%
		100%	100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.
**The maximum exposure to Corporate floating and variable rate debt securities in the Working Capital Portfolio is 10 percent.
***The Working Capital portfolio may not be invested in AMLIP.
****The Working Capital and Internally Managed Portfolio contained an excess of cash equivalents at December 31, 2017 in anticipation of planned spending w ithin a w eek. The portfolios w ere back in compliance the first w eek of 2018.

Investment Type	Concentration Limit	Working Capital Portfolio Holding % at December 31, 2016	Internally Managed Holding % at December 31, 2016
U.S. Government Securities*	50% to 100% of investment portfolio	52%	51%
Repurchase Agreements	0% to 50% of investment portfolio	25%	0%
Certificates of Deposit**	0% to 50% of investment portfolio Maximum 5% per issuer	0%	0%
Bankers Acceptances	0% to 25% of investment portfolio Maximum 5% per issuer	0%	0%
Commercial Paper	0% to 15% of investment portfolio Maximum 5% per issuer	0%	0%
Corporate Bonds	0% to 15% of investment portfolio Maximum 5% per issuer	8%	8%
Alaska Municipal League Investment Pool (AMLIP)***	0% to 25% of investment portfolio	0%	0%
Money Market Mutual Funds	0% to 25% of investment portfolio	15%	41%
Dollar Denominated Fixed Income Securities, other than those listed herein, rated by at least one nationally recognized rating agency	0% to 15% of investment portfolio Maximum 5% per issuer	0%	0%
		100%	100%

*Includes debt obligations issued or guaranteed by the U.S. government, U.S. agencies or U.S. government-sponsered corporations.
**The policy limits CDs that are not secured by U.S. government securities to 20% of the internally managed portfolio.
***The Working Capital portfolio may not be invested in AMLIP.

(b) *Beluga River Asset Retirement Obligation Fund*

Funds set aside to pay for dismantling, removing, and restoring assets of the Beluga River Unit gas field were transferred from the MOA Central Treasury to a separate investment portfolio in 2017, per assembly ordinance.

The Beluga River Asset Retirement Obligation Fund is managed to maximize capital appreciation with a long-term rate of return. The Fund is authorized to invest in the following assets:

- Domestic equities and International equities, including real estate investment trusts.
- Investment grade dollar-denominated fixed income securities.
- Cash and money market instruments.

The Beluga River Asset Retirement Obligation Fund limits the concentration of its investments as follows:

Investment Type	Lower Limit	Upper Limit	Investment Holding % at December 31, 2017
Domestic Equities:			
Large Cap	5%	20%	13%
Mid Cap	0%	5%	2%
Small Cap	0%	5%	2%
International Equities:			
Developed	0%	10%	5%
Emerging Markets	0%	5%	1%
Real Estate:			
Real Estate Funds	1%	4%	4%
Fixed Income:			
Domestic Fixed Income	55%	75%	62%
TIPS	5%	15%	7%
Cash & Cash Equivalents:			
Cash Equivalents	0%	15%	4%
			100%

(c) *Interest Rate Risk*

Interest rate risk is the risk that changes in interest rates will adversely affect the fair value of an investment. The externally managed portfolios of the Municipal Central Treasury utilize the duration method to measure exposure to interest rate risk. All other funds disclose interest rate risk through the segmented time distribution tables within this note, which categorize fixed income investments according to their maturities.

Duration is a measure of an investment's sensitivity to interest rate changes, and represents the sensitivity of an investment's market price to a one percent change in interest rates. The effective duration of an investment is determined by its expected future cash flows, factoring in uncertainties introduced through options, prepayments, and variable rates. The effective duration of a pool is the average fair value weighted effective duration of each security in the pool.

AMC 6.50.030 requires the Working Capital Portfolio have a duration of zero to 270 days. At December 31, 2017, the Working Capital Portfolio had a duration of 0.14 years, or approximately 51 days. At December 31, 2016, the Working Capital Portfolio had a duration of 0.16 years, or approximately 58 days. AMC 6.50.030 also requires that the Contingency Reserve Portfolio have an average duration within half a year of its benchmark. At December 31, 2017, the Contingency Reserve Portfolio had a duration of 1.94 years as compared to its benchmark, Barclays 1-3 Year Government Index, which had a duration of 1.91 years. At December 31, 2016, the Contingency Reserve Portfolio had a duration of 1.88 years as compared to its benchmark, Barclays 1-3 Year Government Index, which had a duration of 1.92 years. AMC 6.50.030 requires the Strategic Reserve Portfolio have a maximum duration no greater than one year in excess of its benchmark. At December 31, 2017, the Strategic Reserve Portfolio had a duration of 3.70 years as compared to its benchmark, Barclays Intermediate Government/Corporate Index, which had a duration of 3.73 years. At December 31, 2016, the Strategic Reserve Portfolio had a duration of 3.88 years as compared to its benchmark, Barclays Intermediate Government/Corporate Index, which had a duration of 3.86 years.

The effective durations of the externally managed portfolios of the Municipal Central Treasury (working capital, contingency reserve and strategic reserve) at December 31, 2017, were 0.14 years, 1.94 years, and 3.70 years, respectively, which are within the required durations per the policy. The effective durations of the externally managed portfolios of the Municipal Central Treasury (working capital, contingency reserve and strategic reserve) at December 31, 2016, were 0.16 years, 1.88 years, and 3.88 years, respectively, which are within the required durations per the policy

(d) Credit Risk

Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations. For fixed income securities, this risk is generally expressed as a credit rating.

At December 31, 2017, the Municipal Central Treasury's investment in marketable debt securities, excluding U.S. Treasury and Agency securities, totaled $175,487,521. The distribution of ratings on these securities was as follows:

Moody's		S&P	
Aaa	17%	AAA	15%
Aa	4%	AA	2%
A	20%	A	19%
Baa	22%	BBB	26%
Ba or Lower	30%	BB or Lower	28%
Not Rated	7%	Not Rated	10%
	100%		100%

At December 31, 2016, the Municipal Central Treasury's investment in marketable debt securities, excluding U.S. Treasury and Agency securities, totaled $208,464,246. The distribution of ratings on these securities was as follows:

Moody's		S&P	
Aaa	16%	AAA	17%
Aa	6%	AA	5%
A	21%	A	21%
Baa	23%	BBB	25%
Ba or Lower	20%	BB or Lower	20%
Not Rated	14%	Not Rated	12%
	100%		100%

(e) Concentration of Credit Risk

Concentration of credit risk is the risk of loss attributed to the magnitude of an entity's investment in a single issuer. GASB Statement No. 40 requires disclosure when the amount invested in a single issuer exceeds 5 percent or more of total investments. Investments issued or explicitly guaranteed by the U.S. Government, as well as mutual funds and other pooled investments, are exempted from this requirement.

At December 31, 2017 and 2016, the Municipal Central Treasury had no investments in any single issuer exceeding 5 percent of total investments.

(f) Custodial Credit Risk

Custodial credit risk is the risk, in event of the failure of a depository institution, that an entity will not be able to recover deposits or collateral securities in the possession of an outside party. For investments, custodial credit risk is the risk, in event of the failure of the counterparty to a transaction, that an entity will not be able to recover the value of the investment or collateral securities in the possession of an outside party. At December 31, 2017 and 2016, the Municipal Central Treasury had bank deposit carrying amounts totaling $56,372,735 and $50,179,132, respectively of which $500,000 was covered by federal depository insurance. Bank deposits of $1,760,720 at December 31, 2017 and $13,478,739 at December 31, 2016 were secured by collateral held by a third party. Deposits of $54,112,015 and $36,200,393 at December 31, 2017 and 2016, respectively, were secured by collateral held at the depository bank. All collateral consists of obligations issued, or fully insured or guaranteed as to payment of principal and interest, by the United States of America, an agency thereof or a United States government sponsored corporation, with market value not less than the collateralized deposit balances.

AMC 6.50.030 requires that repurchase agreements be secured by obligations of the U.S. government, U.S. agencies, or U.S. government-sponsored corporations and agencies. As of December 31, 2017 and 2016 cash deposits and investments were not exposed to custodial risk.

(g) Foreign Currency Risk

Foreign currency risk is the risk that changes in exchange rates will adversely impact the fair value of an investment. The Municipality has no specific policy addressing foreign currency risk; however foreign currency risk is managed through the requirements of AMC 6.50.030 and the asset allocation policies of each portfolio. The Municipal Central Treasury is not exposed to foreign currency risk because AMC 6.50.030 explicitly prohibits the purchase of securities not denominated in U.S. Dollars. At December 31, 2017 and 2016, all debt obligations held in the Municipal Central Treasury were payable in U.S. Dollars.

(h) Fair Value Measurements

At December 31, 2017 and 2016, the Municipality had the following cash and investments, valued as follows:

- Asset-backed securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Bank loan investments are valued at Net Asset Value (NAV) of units held. The NAV is used as a practical expedient to estimate fair value. The NAV is based on the fair value of the underlying investments held by the fund less its liability.
- Short-term collective investments such as money market funds are valued at amortized cost.
- Certificates of deposit are valued at the daily price quoted by the financial institution holding the investment for the Municipality.
- Commercial paper is valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Common stocks are valued at the closing price reported on the active market on which the individual securities traded.
- Corporate bonds are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.
- Commingled funds are valued at the daily closing price as reported by the fund. These funds publish their daily NAV and transact at that price. The commingled funds held are deemed to be actively traded.
- Domestic equity funds are valued at the closing price reported on the active market on which the individual funds traded.
- Fixed income funds are valued at the closing price reported on the active market on which the individual funds traded.
- Fixed Income funds (MOA Trust) are valued at NAV of units held. The NAV is used as a practical expedient to estimate fair value. The NAV is based on the fair value of the underlying investments held by the fund less its liability.
- International equity funds are valued at the closing price reported on the active market on which the individual funds traded.
- Municipal bonds are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings.

- Real estate funds are valued at NAV of units held. The NAV is used a practical expedient to estimate fair value. The NAV is based on the fair value of the underlying investments held by the fund less its liability. This practical expedient is not used when it is determined to be probable that the fund will sell the investment for an amount different than the reported NAV.
- Repurchase agreements are valued at the daily closing price as reported using the daily price quoted by the financial institution holding the investment for the Municipality.
- U.S. treasuries are valued at the closing price reported on the active market on which the individual securities traded.
- U.S. agencies are valued using pricing models maximizing the use of observable inputs for similar securities.
- U.S. Tips are valued at the closing price reported on the active market on which the individual securities traded.

The Municipality utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Municipality determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: quoted prices for identical assets or liabilities in active markets
- Level 2 Inputs: quoted prices for similar assets or liabilities in active or inactive markets; or inputs other than quoted prices that are observable
- Level 3 Inputs: significant unobservable inputs for assets or liabilities

The Municipality categorizes its fair value measurements within the fair value hierarchy established by generally accepted accounting principles. The Municipality as a whole has the following recurring fair value measurements as of December 31, 2017 and 2016:

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND

Notes to Financial Statements

December 31, 2017 and 2016

December 31, 2017

Investment Type:	December 31, 2017	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
Interim Rate Increase Escrow Money Market	$ 27,250,254		
Central Treasury- Restricted			
Investments Measured at Fair Value			
Commercial Paper	1,535,603	-	1,535,603
U.S. Treasuries	121,706,339	121,706,339	-
U.S. Agencies	13,180,799	-	13,180,799
Asset-backed Securities	34,730,718	-	34,730,718
Corporate Securities	122,048,793	-	122,048,793
	293,202,252	121,706,339	171,495,913
Cash & Money Market Funds	37,673,284		
	37,673,284		
Total Central Treasury- Restricted	$ 330,875,536		
Central Treasury- Unrestricted			
Investments Measured at Fair Value			
Commercial Paper	99,654	-	99,654
U.S. Treasuries	22,840,772	22,840,772	-
U.S. Agencies	21,909,848	-	21,909,848
Asset-backed Securities	2,253,879	-	2,253,879
Corporate Securities	7,920,460	-	7,920,460
	55,024,613	22,840,772	32,183,841
Cash & Money Market Funds	32,165,339		
	32,165,339		
Total Central Treasury- Unrestricted	$ 87,189,952		
Asset Retirement Obligation Fund			
Investments Measured at Fair Value			
U.S. Fixed Income	$ 8,220,807	$ 3,818,364	$ 4,402,443
U.S. TIPS	942,226	942,226	-
U.S. Large-Cap Equity	1,751,027	1,751,027	-
U.S. Mid-Cap Equity	265,692	265,692	-
U.S. Small-Cap Equity	261,154	261,154	-
International Developed Equity	657,596	657,596	-
Emerging Markets Equity	133,715	133,715	-
Real Estate	510,327	510,327	-
	12,742,544	8,340,101	4,402,443
Cash & Money Market Funds	456,333		
Total Asset Retirement Obligation Fund	$ 13,198,877		

December 31, 2016

Investment Type:	December 31, 2016	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Fair Value Measurements Using: Significant Other Observable Inputs (Level 2)
Central Treasury- Unrestricted			
Investments Measured at Fair Value			
Repurchase Agreements	$ 34,032,002	$ -	$ 34,032,002
Commercial Paper	3,515,419	-	3,515,419
U.S. Treasuries	123,312,501	123,312,501	-
U.S. Agencies	66,705,430	-	66,705,430
Municipal Bonds	231,288	-	231,288
Asset-backed Securities	46,245,507	-	46,245,507
Corporate Securities	137,193,556	-	137,193,556
	411,235,703	123,312,501	287,923,202
Cash & Money Market Funds	6,556,270		
Certificates of Deposits	2,824,520		
	9,380,790		
Total Central Treasury- Unrestricted	$ 420,616,493		
Central Treasury- Restricted			
Investments Measured at Fair Value			
Repurchase Agreements	$ 2,902,556	$ -	$ 2,902,556
Commercial Paper	299,827	-	299,827
U.S. Treasuries	13,307,427	13,307,427	-
U.S. Agencies	39,384,533	-	39,384,533
Municipal Bonds	19,726	-	19,726
Asset-backed Securities	3,944,233	-	3,944,233
Corporate Securities	16,708,812	-	16,708,812
	76,567,114	13,307,427	63,259,687
Cash & Money Market Funds	47,692,839		
Certificates of Deposits	240,900		
	47,933,739		
Total Central Treasury- Restricted	$ 124,500,853		

(3) Capital Assets

A summary of capital assets at December 31, 2017 follows:

		January 1, 2017	Additions	Deductions	December 31, 2017
Electric plant in service	$	948,075,842	28,786,514	(1,784,363)	975,077,993
Less accumulated depreciation		232,593,710	30,819,404	(1,729,505)	261,683,609
Net electric plant in service		715,482,132	(2,032,890)	(54,858)	713,394,384
Natural gas production and gathering plant		345,231,780	-	-	345,231,780
Less accumulated depletion		182,975,820	11,418,229	(6,689)	194,387,360
Net gas plant in service		162,255,960	(11,418,229)	6,689	150,844,420
Net electric and gas plant in service		877,738,092	(13,451,119)	(48,169)	864,238,804
Intangible plant, less accumulated amortization of $12,661,781 in 2017 and $12,556,509 in 2016		2,715,719	-	(105,272)	2,610,447
Construction work in progress		15,783,204	30,071,559	(22,897,323)	22,957,440
Total capital assets	$	896,237,015	16,620,440	(23,050,764)	889,806,691

Included in the Construction Work in progress are retirement assets as follows:

	$	185,544	648,612	(65,164)	768,992

In accordance with the requirements of FERC, disposals of retirement assets are not placed in service, rather they are reported as deductions from accumulated depreciation.

A summary of capital assets at December 31, 2016 follows:

		January 1, 2016	Additions	Deductions	December 31, 2016
Electric plant in service	$	665,382,025	319,854,999	(37,161,182)	948,075,842
Less accumulated depreciation		237,510,748	23,481,805	(28,398,843)	232,593,710
Net electric plant in service		427,871,277	296,373,194	(8,762,339)	715,482,132
Natural gas production and gathering plant		234,240,102	111,014,149	(22,471)	345,231,780
Less accumulated depletion		164,257,080	18,718,740	-	182,975,820
Net gas plant in service		69,983,022	92,295,409	(22,471)	162,255,960
Net electric and gas plant in service		497,854,299	388,668,603	(8,784,810)	877,738,092
Intangible plant, less accumulated amortization of $12,556,509 in 2016 and $12,253,323 in 2015		3,018,904	-	(303,185)	2,715,719
Construction work in progress		258,306,152	194,619,035	(437,141,983)	15,783,204
Total capital assets	$	759,179,355	583,287,638	(446,229,978)	896,237,015

Included in the Construction Work in progress are retirement assets as follows:

	$	39,473	487,022	(340,951)	185,544

In accordance with the requirements of FERC, disposals of retirement assets are not placed in service, rather they are reported as deductions from accumulated depreciation.

The Utility's construction budget for 2017 is $42,764,000.

(4) Short-Term Debt

In February 2012, the Assembly authorized the issuance of commercial paper in one or more series in the aggregate principal amount not to exceed three hundred million dollars ($300,000,000).

In April 2015, the Utility redeemed all outstanding commercial paper and entered into a short-term borrowing agreement with Wells Fargo Municipal Capital Strategies, LLC, herein referred to as the Direct Drawdown Purchase Program (DDPP). This borrowing program continued to fulfill the purpose of the Commercial Paper program, but at a lower aggregate fee and interest cost to the Utility over the life of the program. The DDPP was used by the Utility to complete construction of Generation Plant 2A. At December 31, 2016 the outstanding balance of DDPP notes payable was $181,000,000. During 2017, $10,900,000 was drawn down for completion of Generation Plant 2A. On November 30, 2017 the loan term was extended to November 29, 2019. At December 31, 2017 the balance was $191,900,000 and the notes were reclassified as long-term notes payable on the Utility's Statement of Net Position, as the principal is not expected to be paid within one year.

(5) Long-Term Liabilities

A summary of long-term liabilities consist of the following at December 31:

		2017	2016
Revenue bonds:			
2005 Series A, effective interest rate at 4.993858% due 2026	$	17,565,000	22,705,000
2009 Series A, effective interest rate at 5.009% due 2039		15,240,000	15,240,000
2009 Series B, effective interest rate at 5.009% due 2039 taxable		114,760,000	114,760,000
2014 Series A, effective interest rate at 3.81% due 2044		175,805,000	178,185,000
		323,370,000	330,890,000
Less:			
Current installments		(7,865,000)	(7,520,000)
Unamortized discount		(476,692)	(507,779)
Unamortized premium		18,721,619	20,104,669
	$	333,749,927	342,966,890

Debt service requirements to maturity at December 31, 2017 are as follows:

		Senior Lien Electric Revenue Bonds		
		Principal	Interest	Total
2018	$	7,865,000	17,313,097	25,178,097
2019		7,730,000	16,950,747	24,680,747
2020		8,075,000	16,603,147	24,678,147
2021		8,410,000	16,268,347	24,678,347
2022		8,760,000	15,917,897	24,677,897
2023-2027		50,570,000	72,518,785	123,088,785
2028-2032		63,490,000	56,987,657	120,477,657
2033-2037		79,780,000	36,583,462	116,363,462
2038-2042		66,840,000	13,095,887	79,935,887
2043-2044		21,850,000	1,319,600	23,169,600
Senior revenue bonds payable	$	323,370,000	263,558,626	586,928,626

The Utility's revenue bonds bear interest at effective rates of 3.75% to 6.5% and require the establishment of reserves over a five-year period at least equal to the maximum annual debt service on all outstanding senior lien bonds. The senior lien revenue bond covenants further stipulate that net revenue before depreciation and amortization for each year will be equal to at least 1.35 times the debt service requirements for that year. At December 31, 2017 and 2016, the Utility had satisfied the reserve requirements and debt service covenants.

Notes payable were reclassified from short-term to long-term in 2017. See Note 4 for further information regarding notes payable.

The following is a summary of long-term liability activity as of December 31, 2017 and 2016:

		Balance January 1, 2017	Additions	Reductions	Balance December 31, 2017	Due within one year
Revenue bonds payable:						
Series 2005A	$	22,705,000	-	5,140,000	17,565,000	5,415,000
Series 2009A		15,240,000	-	-	15,240,000	-
Series 2009B		114,760,000	-	-	114,760,000	-
Series 2014A		178,185,000	-	2,380,000	175,805,000	2,450,000
Senior electric revenue bonds		330,890,000	-	7,520,000	323,370,000	7,865,000
Unamortized premiums/discounts		19,596,890	-	1,351,963	18,244,927	-
Total revenue bonds payable		350,486,890	-	8,871,963	341,614,927	7,865,000
Notes payable *		-	191,900,000	-	191,900,000	-
Compensated absences payable		2,974,329	2,178,541	2,340,730	2,812,140	2,812,140
Net pension liability		15,093,423	-	2,822,530	12,270,893	-
Asset retirement obligation		15,135,086	688,646	-	15,823,732	-
Total long term liabilities	$	383,689,728	194,767,187	14,035,223	564,421,692	10,677,140

* Notes payable reclassified to long term in 2017

		Balance January 1, 2016	Additions	Reductions	Balance December 31, 2016	Due within one year
Revenue bonds payable:						
Series 2005A	$	27,780,000	-	5,075,000	22,705,000	5,140,000
Series 2009A		15,240,000	-	-	15,240,000	-
Series 2009B		114,760,000	-	-	114,760,000	-
Series 2014A		180,575,000	-	2,390,000	178,185,000	2,380,000
Senior electric revenue bonds		338,355,000	-	7,465,000	330,890,000	7,520,000
Unamortized premiums/discounts		21,034,311	-	1,437,421	19,596,890	-
Total revenue bonds payable		359,389,311	-	8,902,421	350,486,890	7,520,000
Compensated absences payable		2,647,510	2,586,196	2,259,377	2,974,329	2,974,329
Net pension liability		10,494,008	4,599,415	-	15,093,423	-
Asset retirement obligation		8,535,928	6,599,158	-	15,135,086	-
Total long term liabilities	$	381,066,757	13,784,769	11,161,798	383,689,728	10,494,329

(6) Net Position

Net position is composed of the following at December 31:

		2017	2016
Total Plant	$	889,806,691	896,237,015
Less: Total revenue bond payable		(341,614,927)	(350,486,890)
Contributions in aid of construction		(180,608,877)	(177,321,176)
Notes payable		(191,900,000)	(181,000,000)
Unspent revenue bond proceeds/note proceeds		-	2,525,855
Bond proceeds used for bond reserve fund		23,673,741	23,358,059
Bond proceeds used for bond sale costs		1,449,969	1,572,299
Deferred loss on refunding		248,700	516,907
Net investment in capital assets		201,055,297	215,402,069
Debt service account		2,098,515	2,098,291
Revenue bond reserve investments		23,335,230	23,143,622
Less: Bond proceeds used for bond reserve fund		(23,673,741)	(23,358,059)
Accrued bond interest payable		(1,688,922)	(1,614,313)
Restricted for debt service		71,082	269,541
Operating reserve -			
Restricted for operations		14,235,000	13,200,000
Unrestricted		54,095,867	25,694,823
Total net position	$	269,457,246	254,566,433

(7) Retirement Plans

Substantially all regular employees of the Utility are covered by one of the following plans:

(a) IBEW Plans

Defined Benefit Plan

The Utility's IBEW members participate in a cost-sharing defined benefit plan, *the Alaska Electrical Pension Plan of the Alaska Electrical Pension Fund* (the Plan). The Alaska Electrical Trust Funds (AETF) Board of Trustees administers the Plan and has the authority to establish and amend benefit terms and approve changes in employer required contributions. Each year, AETF issues annual financial reports that can be obtained by writing the plan administrator, Alaska Electrical Pension Trust, 2600 Denali Street, Suite 200, Anchorage, Alaska, 99503. The Utility had 181 and 172 employees covered by the Plan as of December 31, 2017 and 2016, respectively.

The Plan provides several levels of retirement benefits, including early retirement, normal retirement, late retirement, and disability retirement and includes several options for spouse participation and death benefits. The Utility contributes to the Plan for its covered employees according to the terms of its Agreement Covering Terms and Conditions of Employment (Agreement) with the IBEW Local 1547. The Agreement in effect during 2015 and 2016 expired on December 31, 2016. A new agreement was approved subsequent to year end and is effective from February 28, 2017 to December 31, 2019. The Agreement automatically renews for a period of one year from its expiration date and for successive periods of one year each thereafter for so long as there is no proper notification of an intent to negotiate a successor Agreement.

Employer contributions are determined from hours of work reported by participating employers and the contractual employer contribution rate in effect. The Utility's required contribution to the plan for each hour for which compensation is paid to the employee for February 28, 2017 to December 31, 2017 was $7.85, and from January 1, 2016 to February 27, 2017 was $7.75. The Utility's total employer contributions to the Plan for 2017 and 2016 were $3,272,545 and $3,396,484, respectively. The Utility had $251,784 and $123,849 in required contributions to the Plan payable to AETF at December 31, 2017 and 2016, respectively. These amounts are paid during the normal course of business in the month following each year end. The Utility is not subject to withdrawal penalties, nor are there any future minimum payments to the Plan required other than the contribution per hour compensated as required by the Agreement.

Money Purchase Plan

The Agreement requires employer contributions to be made in an amount of 1.9% (1.8% in 2016) of each employee's gross wages to the Alaska Electrical Workers Money Purchase Plan (Money Purchase Plan). The Utility's employer and employee contributions to the Money Purchase Plan during 2017 were $499,127 and $98,610, respectively. The Utility's employer and employee contributions to the Money Purchase Plan during 2016 were $412,473 and $85,362, respectively.

One hundred percent (100%) of the Utility's required contributions to the IBEW plans have been made through these contributions to the AETF.

(b) State of Alaska Public Employees' Retirement System Defined Benefit Plan (PERS I-III)

General Information About the Plan

The Municipality participates in the Alaska Public Employees' Retirement System (PERS I-III or the Plan). PERS I-III is a cost-sharing multiple employer plan which covers eligible State and local government employees, other than teachers. The Plan was established and is administered by the State of Alaska Department of Administration. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

The Plan provides for retirement, death and disability, and post-employment health care benefits. There are three tiers of employees, based on entry date. For all tiers within the Defined Benefit (DB) plan, full retirement benefits are generally calculated using a formula comprised of a multiplier times the average monthly salary (AMS) times the number of years of service. The multiplier is increased at longevity milestone markers for most employees. The tiers within the Plan establish differing criteria regarding normal retirement age, early retirement age, and the criteria for calculation of AMS, COLA adjustments, and Other Post-Employment Benefits (OPEB) benefits.

A complete benefit comparison chart is available at the website noted below.

The Plan is included in a comprehensive annual financial report that includes financial statements and other required supplemental information. That report is available via the internet at http://doa.alaska.gov/drb/pers. Actuarial valuation reports, audited financial statements, and other detailed plan information are also available on this website. They may be obtained by writing to the State of Alaska, Department of Administration, Division of Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811-0203 or by phoning (907) 465-4460.

The PERS I-III DB Plan was closed to new entrants effective June 30, 2006. New employees hired after that date participate in the PERS IV Defined Contribution (DC) Plan described later in the note.

Historical Context and Special Funding Situation
In April 2008, the Alaska Legislature passed legislation converting the previously existing PERS plan from an agent-multiple employer plan to a cost-sharing plan with an effective date of July 1, 2008. In connection with this conversion, the State of Alaska passed additional legislation which statutorily capped the employer contribution rate, established a state funded "on-behalf" contribution (subject to funding availability), and required that employer contributions be calculated against all PERS eligible wages, including wages paid to participants of the PERS Tier IV defined contribution plan described later in this note.

Alaska Statute requires the State of Alaska to contribute to the Plan an amount such that, when combined with the employer contribution, is sufficient to pay the Plan's past service liability contribution rate as adopted by the Alaska Retirement Management Board. Although current statutes call for the State of Alaska to contribute to the Plan, the Alaska Department of Law determined that the statute does not create a legal obligation to assume the liabilities of the Plan; rather it establishes a contribution mechanism to provide employer relief against the rising contribution rates. This relief payment is subject to funding availability, and therefore not legally mandated. As a result, the State initially determined that the Plan is not in a special funding situation. Following much discussion with various stakeholders, participant communities, attorneys, auditors, and the GASB itself, the State has subsequently reversed its position on this matter, and as of June 30, 2015, the State did record the liability presuming that the current statute does constitute a special funding situation as the legislation is currently written. It is important to note that the Alaska Legislature has the power and authority to change the aforementioned statute through the legislative process, and it is likely that the State will pursue efforts to do so in a future legislative session. For the current year financial statements, management has treated AS 39.35.255 as constituting a special funding situation under GASB Statement No. 68 rules and has recorded all pension related liabilities, deferred inflows and outflows of resources, and disclosures on this basis.

Employee Contribution Rates
Regular employees are required to contribute 6.75 percent of their annual covered salary.

Employer and Other Contribution Rates

There are several contribution rates associated with the pension and healthcare contributions and related liabilities. These amounts are calculated on an annual basis.

Employer Effective Rate

This is the contractual employer pay-in rate. Under current legislation, this rate is statutorily capped at 22 percent of eligible wages, subject to a wage floor, and other termination events. This 22 percent rate is calculated on all PERS participating wages, including those wages attributable to employees in the defined contribution plan. Contributions derived from the defined contribution employees are referred to as the Defined Benefit Unfunded Liability (DBUL) contribution.

Alaska Retirement Management Board (ARM) Adopted Rate

This is the rate formally adopted by the ARM Board. This rate is actuarially determined and used to calculate annual Plan funding requirements, without regard to the statutory rate cap or the GASB accounting rate. Prior to July 1, 2015, there were no constraints or restrictions on the actuarial cost method or other assumptions used in the ARM Board valuation. Effective July 1, 2015, the Legislature requires the ARM Board to adopt employer contribution rates for past service liabilities using a level percent of pay method over a closed 25 year term which ends in 2039. This will result in lower ARM Board Rates in future years (as demonstrated in the contribution rate tables below).

On-behalf Contribution Rate

This is the rate paid in by the State as an on-behalf payment under the current statute. The statute requires the State to contribute, based on funding availability, an on-behalf amount equal to the difference between the ARM Board Rate and the Employer Effective Rate. However, in state fiscal year 2015, the State Legislature appropriated a one-time contribution to the Plan in the amount of $1 billion. As a result, the On-behalf Contribution Rate for State Fiscal Year 2015 (July 1, 2014 through June 30, 2015) significantly exceeds the statutory amount. In the 2017 and 2016 Utility financial statements, the on-behalf amounts reflect revenue and expense only during the measurement period July 1, 2016 to June 20, 2017 and July 1 2015 to June 30, 2016, respectively. During the measurement period the Plan recognizes the payments, resulting in a significant timing difference between the cash transfers and revenue and expense recognition. Total on-behalf amounts recognized as of the measurement period are actuarially calculated.

GASB Rate

This is the rate used to determine the long-term pension and healthcare liability for plan accounting purposes in accordance with generally accepted accounting principles as established by GASB. Certain actuarial methods and assumptions for this rate calculation are mandated by GASB. Additionally, the GASB Rate disregards all future Medicare Part D payments. For Fiscal Year 2017 and 2016, the GASB rate uses an 8 percent pension discount rate and a 4.55 and 4.3 percent healthcare discount rate, respectively.

The GASB Rate and the ARM Board Adopted Rate differ significantly as a direct result of variances in the actuarial methods and assumptions used.

Contribution rates for the plan years ended June 30, 2016 and June 30, 2017 were determined in the June 30, 2014 and June 30, 2015 actuarial valuations, respectively. Municipality contribution rates for the 2017 and 2016 calendar years were as follows:

January 1, 2016 to June 30, 2016	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	13.25%	19.04%	3.63%	37.79%
Postemployment healthcare	8.75%	8.15%	1.56%	58.73%
Total Contribution Rates	22.00%	27.19%	5.19%	96.52%

July 1, 2016 to December 31, 2016	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	14.96%	20.34%	4.14%	24.49%
Postemployment healthcare	7.04%	5.80%	0.00%	56.64%
Total Contribution Rates	22.00%	26.14%	4.14%	81.13%

January 1, 2017 to June 30, 2017	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	14.96%	20.34%	4.14%	24.49%
Postemployment healthcare	7.04%	5.80%	0.00%	56.64%
Total Contribution Rates	22.00%	26.14%	4.14%	81.13%

July 1, 2017 to December 31, 2017	Employer Effective Rate	ARM Board Adopted Rate	State Contribution Rate	GASB Rate
Pension	17.12%	21.90%	3.01%	29.07%
Postemployment healthcare	4.88%	3.11%	0.00%	66.85%
Total Contribution Rates	22.00%	25.01%	3.01%	95.92%

In 2017 and 2016, the Municipality was credited with the following contributions into the pension plan.

	Measurement Period	Municipality's Fiscal Year	Measurement Period	Municipality's Fiscal Year
	July 1, 2015 to June 30, 2016	January 1, 2016 to December 31, 2016	July 1, 2016 to June 30, 2017	January 1, 2017 to December 31, 2017
Employer contributions (including DBUL)	$ 22,688,610	$ 24,562,145	$ 26,149,321	$ 28,704,730
Nonemployer contributions (on-behalf)	8,178,642	8,890,546	9,460,308	8,343,294
Total Contributions	$ 30,867,252	$ 33,452,691	$ 35,609,629	$ 37,048,024

The Utility's share of employer contributions to the plan for fiscal year 2017 and 2016 were $940,338 and $854,217, respectively. In addition, municipal employee contributions to the Plan totaled $8,849,904 and $9,135,197 during 2017 and 2016, respectively.

Pension Liabilities, Pension Expense, Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pensions

The Utility's portion of the Municipality's liabilities, pension expense, deferred outflows and inflows of resources related to pensions are based on its share of the Municipality's contributions to the plan in the current year. Those proportions are 3.53% and 3.48% at December 31, 2017 and 2016, respectively.

At December 31, 2017 and 2016, the Municipality reported a liability for its proportionate share of the net pension liability (NPL) that reflected a reduction for State pension support provided to the Municipality. The amount recognized by the Municipality and the Utility for their proportional share, the related State proportion, and the total were as follows:

December 31,	2017		2016	
	Municipality	Utility	Municipality	Utility
Proportionate Share of NPL	$ 347,836,470	$ 12,270,893	$ 433,996,281	$ 15,093,423
State's proportionate share of NPL associated with the Municipality	129,589,885	4,571,641	54,685,280	1,901,832
Total Pension Liability	$ 477,426,355	16,842,534	$ 488,681,561	$ 16,995,255

The Utility recorded a net pension liability of $12,270,893 and $15,093,423 at December 31, 2017 and 2016, respectively.

The total pension liability for the June 30, 2017 measurement date was determined by an actuarial valuation as of June 30, 2016 rolled forward to June 30, 2017 to calculate the net pension liability as of that date. The total pension liability for the June 30, 2016 measurement date was determined by an actuarial valuation as of June 30, 2015 rolled forward to June 30, 2016 to calculate the net pension liability as of that date. The Municipality's proportion of the net pension liability was based on a projection of the Municipality's long-term share of contributions to the pension plan relative to the projected contributions of all participating entities, including the State, actuarially determined. At the June 30, 2017 measurement date, the Utility's proportionate share was 0.23737 percent, a decrease of 0.03266 percent from the prior year. At the June 30, 2016 measurement date, the Utility's proportionate share was 0.27003 percent, an increase of 0.05366 percent from the prior year.

The Utility recognized pension expense of $573,752 and $2,858,253 for the year ended December 31, 2017 and December 31, 2016, respectively, of which $336,953 and $317,044 were recorded as on-behalf revenue and expense for additional contributions paid by the State.

At December 31, 2017 and 2016, the Utility reported deferred outflows of resources and deferred inflows of resources related to pensions from the following sources:

	Measurement Period June 30, 2017		Measurement Period June 30, 2016	
	Deferred Outflows of Resources	Deferred Inflows of Resources	Deferred Outflows of Resources	Deferred Inflows of Resources
Difference between expected and actual experience	$ -	$ (206,881)	$ 1,388	$ (168,242)
Changes in assumptions	-	-	69,615	-
Net difference between projected and actual earnings on pension plan investr	356,477	-	1,483,621	-
Changes in proportion and differences between Utility contributions and proportionate share of contributions	130,754	(796,532)	1,338,972	-
Utility contributions subsequent to the measurement date	636,903	-	454,696	-
Total Deferred Outflows and Deferred Inflows Related to Pensions	$ 1,124,134	(1,003,413)	$ 3,348,292	$ (168,242)

The Utility recorded $1,124,134 and $1,003,413 at December 31, 2017 and $3,348,292 and $168,242 at December 31, 2016 as deferred outflows and deferred inflows of resources related to pensions, respectively.

The $636,903 reported by the Utility in 2017 as deferred outflows of resources related to pensions resulting from contributions subsequent to the measurement date will be recognized as a reduction in the net pension liability in the year ended December 31, 2018. Other amounts reported as deferred outflows of resources and deferred inflows of resources related to pensions will be recognized in pension expense as follows:

Year ending December 31,	Net Amortization of Deferred Outlows and Deferred Inflows of Resources
2018	$ (771,032)
2019	285,277
2020	128,065
2021	(158,492)
Total Amortization	$ (516,182)

The total pension liability for the measurement period ended June 30, 2017 was determined by an actuarial valuation as of June 30, 2016, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2017. The total pension liability for the measurement period ended June 30, 2016 was determined by an actuarial valuation as of June 30, 2015, using the following actuarial assumptions, applied to all periods included in the measurement, and rolled forward to the measurement date of June 30, 2016. The actuarial assumptions used in the June 30, 2016 actuarial valuation (latest available) were based on the results of an actuarial experience study for the period from July 1, 2009 to June 30, 2013, resulting in changes in actuarial assumptions adopted by the ARM Board to better reflect expected future experience. There were no changes in actuarial assumptions from 2016 to 2017.

Inflation	3.12%
Salary Increases	Graded by service, from 9.66% to 4.92% for Peace Officers/Firefighters. Graded by age and service, from 8.55% to 4.34% for all others.
Investment Return / Discount Rate	8.00% net of pension plan investment expenses. This is based on an average inflation rate of 3.12% and real rate of return of over 4.88%.
Mortality (Pre-termination)	Based upon 2010-2013 actual mortality experience, 60% of male and 65% of female of post-termination mortality rates. Deaths are assumed to be occupational 70% of the time for Peace Officers/Firefighters, 50% of the time for Others.
Mortality (Post-termination)	96% of all rates of the RP-2000 table, 2000 Base Year projected to 2018 with Projection Scale BB.

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of pension plan investment expense and inflation) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation. The best estimates of arithmetic real rates of return for each major asset class are summarized in the following table (note that the rates shown below exclude the inflation component. Those estimates for years ending December 31, 2017 and 2016 are as follows:

December 31, 2017

Asset Class	Long-term Expected Real Rate of Return
Domestic equity	8.83%
Global ex-U.S. equity	7.79%
Intermediate treasuries	1.29%
Opportunistic	4.76%
Real assets	4.94%
Absolute return	4.76%
Private equity	12.02%
Cash equivalents	0.63%

December 31, 2016

Asset Class	Long-term Expected Real Rate of Return
Domestic equity	5.35%
Global equity (non-US)	5.55%
Private equity	6.25%
Fixed income composite	0.80%
Real estate	3.65%
Alternative equity	4.70%

Discount Rate

The discount rate used to measure the total pension liability was 8 percent in 2017 and 2016. The projection of cash flows used to determine the discount rate assumed that Employer and

State contributions will continue to follow the current funding policy which meets State statutes. Based on those assumptions, the pension plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Discount Rate Sensitivity
The following presents the Utility's proportionate share of the net pension liability calculated using the discount rate of 8 percent, as well as what the Utility's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1-percentage-point lower (7 percent) or 1-percentage-point higher (9 percent) than the current rate:

December 31, 2017

	Proportional Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utility's proportionate share of the net pension liability	0.23737%	$ 16,118,950	$ 12,270,893	$ 9,021,357

December 31, 2016

	Proportion al Share	1% Decrease (7.00%)	Current Discount Rate (8.00%)	1% Increase (9.00%)
Utility's proportionate share of the net pension liability	0.27003%	$ 19,439,564	$ 15,093,423	$ 11,427,653

Pension Plan Fiduciary Net Position
Detailed information about the pension plan's fiduciary net position is available in the separately issued PERS financial report.

(c) State of Alaska Public Employees' Retirement System Defined Contribution Plan (PERS IV)

Plan Information
The Municipality participates in the Alaska Public Employees' Retirement System (PERS IV or Plan). PERS IV is a Defined Contribution (DC) plan which covers eligible State and local government employees, other than teachers. The Plan was established and is administered by the State of Alaska Department of Administration. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

The Plan is included in a comprehensive annual financial report that includes financial statements and other required supplemental information. That report is available via the internet at http://doa.alaska.gov/drb/pers. Actuarial valuation reports, audited financial statements, and other detailed plan information are also available on this website. They may be obtained by writing to the State of Alaska, Department of Administration, Division of

Retirement and Benefits, P.O. Box 110203, Juneau, Alaska, 99811 0203 or by phoning (907) 465 4460.

Plan Participation and Benefit Terms
The Plan is governed by Section 401(a) of the Internal Revenue Code. A portion of employee wages and a matching employer contributions are made to the Plan before tax. These contributions plus any change in value (interest, gains and losses), and minus any Plan administrative fees or other charges, are payable to the employee or the employee's beneficiary at a future date. The Plan is a participant-directed plan with investment options offered by providers that are selected by the Alaska Retirement Management (ARM) Board.

Employees first enrolling into PERS after July 1, 2006 participate in PERS IV. PERS IV is a defined contribution retirement plan that includes a component of defined benefit post-employment health care.

Plan Contribution Requirements

The plan requires both employer and employee contributions. Employees may make additional contributions into the plan, subject to limitations. Contribution rates are as follows:

	Tier IV	
	1/1 - 6/30	7/1 - 12/31
Employee Contribution	8.00%	8.00%
Employer Contribution		
Retirement	5.00%	5.00%
Health Reimbursement Arrangement	3.00%	3.00%
Retiree Medical Plan	1.18%	1.03%
Death & Disability Benefit	0.17%	0.16%
Total Employer Contribution	9.35%	9.19%

Health Reimbursement Arrangement

Alaska Statute 39.30.370 requires that the employer contribute "an amount equal to three percent of the employer's average annual employee compensation." For actual remittance, this amount is calculated as a flat rate per full time employee and a flat rate per hour for part time employees. Prior to July 1, 2017 a flat rate of approximately $2,049 per year for full time employees and $1.31 per part time hour worked was paid. For pay periods ending after July 1, 2017, a flat rate of approximately $2,084 per year for full time employees and $1.34 per part time hour worked were paid.

For the year ended December 31, 2017, the Municipality contributed $4,467,018 to PERS IV for retirement and retiree medical, and $2,288,200 to PERS IV for Health Reimbursement Arrangement on-behalf of its employees. Employee contributions to the plan totaled $7,160,037.

For the year ended December 31, 2016, the Municipality contributed $3,882,883 to PERS IV for retirement and retiree medical, and $2,021,451 to PERS IV for Health Reimbursement Arrangement on-behalf of its employees. Employee contributions to the plan totaled $6,212,200.

(8) Commitments and Contingencies

The Utility, in the normal course of its activities, is involved in various claims and pending litigation. In the opinion of management and the Municipality's legal department, the disposition of these matters is not expected to have a material adverse effect on the Utility's financial statements.

(a) Environmental

Fuel/Polychlorinated Biphenyl (PCB) Contaminated Sites at Hank Nikkels Power Plant 1 and Operations/Dispatch Center

During the 1964 earthquake, approximately 250,000-400,000 gallons of diesel fuel spilled on the ground. Based on numerous environmental investigations, the spill impacted soil and groundwater at the Hank Nikkels Power Plant 1 and properties west/northwest of the plant. During the 2006-2007 subsurface investigation, in addition to diesel contamination known from the 1964 spill, PCBs were detected in the soil.All soil disturbing activities at the site are governed by the Risk-Based Disposal Plan (RBDP) administered by the Alaska Department of Environmental Conservation (ADEC) and the Environmental Protection Agency (EPA).

In May 2017 The Utility conducted PCB cleanup activities at the plant and paved the surface of the cleanup area in accordance with the 2008 RBDP approved by EPA and ADEC. The Utility recorded a liability for estimated cleanup costs of $760,000 at December 31, 2016. At December 31, 2017 the liability remained at $511,787. All cleanup activities were considered to be performed and the liability was discharged during 2018.

In 2009 PCB contaminated soil was discovered near the Operations/Dispatch building during excavation to install water lines for a fire suppression system. In 2010 and 2015 additional site investigations were conducted to determine a horizontal and vertical extent of PCB contamination. Following the soil investigations the Utility performed monitoring of groundwater at the site and in the vicinity during 2015 and 2016. Analytical results indicated no off-site migration of PCBs. The Utility is waiting on EPA's review of the site data and further decisions. The cost associated with any further actions cannot be determined at this time.

Contaminated Sites Subject to Cleanup Complete or Cleanup Complete with Institutional Controls status

In 2017, ADEC conducted a review of three contaminated sites that have a long history of monitoring and identified two sites that qualified for cleanup complete status and one site (Transformer Shop) that can qualify for the Cleanup Complete with Institutional Controls status if the Utility conducts additional sampling The Utility intends to prepare a work plan and include additional testing into the 2018 biannual groundwater monitoring. Upon receipt of analytical results, the Utility will make a determination how to proceed with obtaining the Cleanup Complete with Institutional Controls Status.

Compliance with Air Quality Permits

The Utility owns three turbines that are subject to hourly and annual emissions limits emission controls for criteria pollutants, NOx and CO. In addition to maintaining continuous emission monitoring systems (CEMS) on each turbine, the two newly installed turbines requires operation with post-combustion emission controls.

EPA regulations require annual third party emissions testing to assure accuracy of the CEMS. Newly installed turbines have significant emissions reductions compared to the existing turbines, however maintaining emissions control equipment and performing all testing required by EPA will add to the overall environmental compliance cost. The Utility will oversee environmental compliance and contract qualified third-party experts to perform necessary services. Environmental permitting and compliance will continue to require a consultant's expertise. The cost of compliance cannot be determined at this time.

(b) Petroleum Production Tax (PPT)

For tax year 2016, the Utility estimated that its PPT liability under AS 43.55.011(e) for non-royalty gas is zero and its liability under AS 43.44.011(i) for private royalty gas is $5,557. Monthly installment payments from February 2016 through January 2017 totaled $5,555, an underpayment of $2.

For tax year 2017, the Utility estimates that its PPT liability under AS 43.55.011(e) for non-royalty gas is $604,171 and its liability under AS 43.44.011(i) for private royalty gas is $5,209. Monthly installment payments from February 2017 through January 2018 totaled $609,380.

(c) Petroleum Production Credits

Pursuant to AS 43.55.023, the Utility applies for Alaska oil and gas tax credits from the State of Alaska Department of Revenue (DOR). The Utility records the receipt of cash from tax credits as a restricted investment and as a deferred inflow of resources for the benefit of customers. During 2017, the Utility did not apply for tax credits and received cash payments of $20,294 for calendar year 2015 credits. During 2016, the Utility applied for tax credits in the amount of $7,776,277 for calendar year 2014 and $2,473,790 for 2015. The Utility received cash payments of $3,357,563. The amounts received by the Utility for tax credits are subject to final resolution of DOR audits, and are not recorded until cash is received.

(d) Contractual Commitments

The Utility has purchase commitments to contractors and suppliers at December 31, 2017 of approximately $7 million. Those commitments are for contracts, materials and services related to construction of the Utility's generation and distribution system assets, regulatory filings and contracted billing services. Construction of plant assets is financed with contributions in aid of construction and Utility equity, and operating commitments are financed with Utility revenues.

(9) Regulatory Matters

(a) Beluga River Unit Underlift Settlements

Until April 2016 the Utility owned a one-third interest in annual production of the BRU. Its field partners at that time - CPAI and Hilcorp Alaska, LLC - each also owned a one-third interest in BRU production. Every BRU owner has a right to take a portion of annually produced gas proportionate to its interest.

In 2005 the Utility underlifted (i.e. took less than its interest in BRU's annual output) and accepted a monetary settlement from its field partners. These funds were deposited in a Future Natural Gas Purchases Account (FGP), and the Utility recorded a deferred inflow of resources for future natural gas purchases. The balances of the Future Natural Gas Purchases Account, as of December 31, 2017 and 2016 were $17,230,809 and $16,477,276, respectively.

In 2015 the Utility petitioned the RCA for authorization to apply 2014 underlift settlement proceeds to reduce its GTP in effect from July 1, 2016 through June 30, 2017. The RCA approved the Utility's unopposed proposal in Order U-15-116(2), dated March 10, 2016.

In April 2016 the Utility purchased 70% of CPAI's one-third interest in the BRU. The RCA approved the Utility's request in Order U-16-012(14), dated April 21, 2016, to utilize a closing underlift settlement from CPAI of $13,177,726 towards financing this acquisition. See Note 9(f).

(b) Regulatory Debits/Credits

The Utility files a COPA rate quarterly with the RCA to recover cost of power expenses not recovered in base rates. The COPA calculation is based on the projected cost of fuel and purchased power for the applicable quarter, the projected kilowatt hour sales for the applicable quarter, and the over- or under- recovered balance in the cost of power clearing account. The Utility records in the cost of power clearing account an asset with an offsetting credit to a contra revenue account for under recovered costs or a liability and an offsetting debit to a contra revenue account for over recovered costs. The Utility over-recovered as of December 31, 2017 in the amount of $4,589,934 and under-recovered as of December 31, 2016 in the amount of $1,358,355.

Prior to October 24, 2017, the Utility annually set the GTP with its third quarter COPA filings. (See Note 8 (g) for the new schedule in filing the GTP.) Through the GTP, the Utility recovers the Gas Fund's annual revenue requirement associated with the Utility's ownership interest in the BRU and any over or under recovery from the prior year. The Utility records in the cost of Gas Transfer Price Clearing Account an asset and a credit to an expense account for under-recovered costs or a liability and debit to an expense account for over-recovered costs. The Utility over-recovered as of December 31, 2017 and December 31, 2016 in the amounts of $7,394,724 and $11,423,366, respectively.

(c) Deferred Regulatory Liability for Gas Sales

Revenue from third party sales of natural gas produced at the BRU is excluded from the GTP calculation. These funds, net of royalties and the ARO surcharge, are recorded in the Utility's Future BRU Construction or Natural Gas Purchases account, referred to for regulatory purposes as the Deferred Regulatory Liability from Gas Sales (DRLGS) Account. These funds are to be used for future BRU construction or natural gas purchases. The balances of the DRLGS account, as of December 31, 2017 and 2016, were $25,002,529 and $20,236,871, respectively.

(d) Asset Retirement Obligation Sinking Fund

ARO expenses associated with future abandonment of the BRU are funded through a surcharge to the Utility's GTP. This surcharge is deposited into a sinking fund. As of December 31, 2017 and 2016, the sinking fund account balances were $13,198,877 and $11,797,445, respectively.

(e) *Revenue Requirement Studies*

On December 30, 2016 the Utility filed a petition with the RCA, based on a 2015 test year revenue requirement study, for interim and permanent across-the-board rate increases in energy and demand charges in order to recover costs associated with its construction of Plant 2A. The Utility requested a 29.49% interim and refundable rate increase, based on RCA approval of the Utility's proposed rate stabilization plan (RSP). On February 13, 2017 the RCA granted the Utility an interim and refundable rate increase of 37.30%, denied approval of the Utility's proposed RSP, and suspended the Utility's request into Docket U-17-008 for further investigation.

A public hearing was held on this matter that began on November 16, 2017, and continued through December 21, 2017. The RCA issued a final order on March 23, 2018 [U-17-008(13)] approving a 37.32% increase in the revenue requirement.

(f) *Acquisition of CPAI's Interest in the BRU*

In Order U-16-012(14), dated April 21, 2016, the RCA granted a joint petition filed by the Utility and CEA requesting approval of a purchase and sale agreement for the acquisition of CPAI's one-third interest in the BRU. The total purchase price was $152 million, with the Utility acquiring 70% of that interest for $106.4 million and CEA the remaining 30% for $45.6 million. The Utility funded its share of the acquisition with DRLGS and Future Natural Gas Purchases Account funds, cumulative and underlift proceeds owed to it by CPAI. This purchase gives the Utility a total 56.67% interest in the BRU.

(g) *BRU Ratemaking and Accounting Treatment - Aggregate BRU Interest*

On June 20, 2016, the Utility filed for approval from the RCA for some changes in the ratemaking and accounting treatment applicable to the Aggregate BRU Interest. Ruling under Docket U-16-060(12), the RCA granted in part the request on October 24, 2017. The use of rate base/rate of return (RB/ROR) methodology to calculate the gas fund revenue requirement beginning in 2019 was approved. The use of a system-wide weighted average cost of capital (WACC) for calculating the gas fund revenue requirement was approved. The RCA also approved the inclusion of depletion expense using the units of production methodology for calculating the gas fund revenue requirement.

Because the GTP is one component of the COPA and Small Facility Power Purchase Rate (SFPPR), several 2017 tariff advice filings were suspended and were filed under Docket U-16-073. On October 24, 2017, these were approved and made permanent.

(h) *Bradley Lake Transmission*

Homer Electric Association, Inc. (HEA) filed a rate case on November 15, 2013 requesting RCA's approval of postage stamp rates for Bradley Lake energy wheeled over HEA's system. The Utility intervened, arguing in part that the Bradley Lake Agreements govern the obligations of Bradley Lake participants and that the RCA was statutorily precluded, under AS 42.05.431(c), from reviewing these wheeling rates. On June 30, 2014, the RCA issued an order establishing interim rates for wheeling Bradley Lake energy from the Soldotna to Quartz Creek Substations. The parties appealed to the state superior court, which ruled May 27, 2015 that the RCA lacks jurisdiction over Bradley Lake wheeling rates. All parties appealed this decision to the Alaska Supreme Court. The parties engaged in lengthy mediation, and filed reply briefs with the Alaska Supreme Court. Oral arguments before the Alaska Supreme Court were heard May 31, 2018. If the Utility is unsuccessful in court, the Utility's wheeling rates could be affected.

(10) Other Matters

(a) Eklutna Hydroelectric Project

On October 2, 1997, the ownership of the Eklutna Hydroelectric Project was formally transferred from the Alaska Power Administration, a unit of the United States Department of Energy, to the three participating utilities: the Utility, CEA and Matanuska Electric Association (MEA). The project is jointly owned and operated by the participating utilities and each contributes their proportionate share for operation, maintenance, and capital improvement costs, as well as maintenance of the transmission line between Anchorage and the hydroelectric plant. The Utility has a 53.33% ownership interest in the project and recorded costs of $2,300,574 and $674,165 in 2017 and 2016, respectively.

(b) Bradley Lake Hydroelectric Project

The Utility agreed to acquire a portion of the output of the Bradley Lake Hydroelectric Project (Project) pursuant to a Power Sales Agreement (Agreement). The Agreement specifies the Utility acquire 25.9% of the output of the Project.

The Project went on line September 1, 1991. The Utility made payments to the Alaska Energy Authority (AEA) of $4,669,706 in 2017 for its portion of costs, and received 95,933 megawatt hours of power from the Project. In 2016 the Utility paid $5,101,368 and received 90,390 megawatt hours. The Utility received a budget surplus refund in the amount of $614,108 for 2017. The Utility's estimated cost of power from the Project for 2018 is $4,961,943.

AEA issued the Power Revenue Bonds, First and Second Series in September 1989 and August 1990, respectively, for the long term financing of the construction costs of the Project. On July 1, 2010, AEA issued $28,800,000 principal amount of Power Revenue Bonds, Sixth Series. The Sixth Series Bonds were issued for the purpose of refunding the Power Revenue Bonds, Fifth Series Bonds to take advantage of lower interest rates. The total amount of debt outstanding as of December 31, 2017 is $44,359,771. The pro rata share of the debt service costs of the Project for which the Utility is responsible, given its 25.9% share of the Project, is $11,489,181. In the event of payment defaults by other power purchasers, the Utility's share could be increased by up to 25%, which would then cause the Utility's pro rata share of Project debt service to be a total of $14,361,476. The Utility does not now know of or anticipate any such defaults.

(c) Southcentral Power Project

The Utility entered into a participation agreement with CEA on August 28, 2008, to proceed with the joint development, construction and operation of SPP. SPP went into service on January 31, 2013. It has a capacity of 200.3 MW, of which the Utility's proportionate share is 60.1 MW, or 30%. The Utility has recorded costs of $5,481,350 and $14,302,236 in 2017 and 2016, respectively.

(11) Subsequent Events

Sale of the Utility

On April 3, 2018, Anchorage voters approved an amendment to the Anchorage Municipal Charter authorizing the Municipality to sell Municipal Light & Power to Chugach Electric Association, Inc. by Municipal ordinance, to be approved no later than December 31, 2018. The Anchorage Assembly approved the sale on December 4, 2018. Proceeds of the sale are to be used to retire Utility and Municipal debt, replace MUSA payments and fund the MOA Trust Fund.

The Municipality and CEA are currently negotiating terms of the proposed sale and due diligence activities are ongoing. The Utility continues to operate as usual and the proposed sale has no material effect on ongoing operations of the Utility.

Earthquake

On November 30, 2018, Anchorage and surrounding areas experienced an earthquake of magnitude 7.0. The Utility continues to assess and repair any damages sustained by its system due to the earthquake. When the costs associated with damage and repairs have been fully assessed, the Utility does not expect uninsured losses to be material.

(12) New Accounting Pronouncements

The Governmental Accounting Standards Board has passed several new accounting standards with upcoming implementation dates. The new accounting standards were considered and determined to be not applicable to the financial statements of the Utility for 2017 reporting.

The following standards are required to be implemented in future financial reporting periods:

- GASB 75 - Accounting and Financial Reporting for Postemployment Benefits Other than Pensions. The provisions of this Statement are required to be implemented for the 2018 financial reporting period.

- GASB 84 - Fiduciary Activities. The provisions of this Statement are required to be implemented for the 2019 financial reporting period.

- GASB 85 - Omnibus 2017. The provisions of this Statement are required to be implemented for the 2018 financial reporting period.

- GASB 86 - Certain Debt Extinguishment Issues. The provisions of this Statement are required to be implemented for the 2018 financial reporting period.

- GASB 87 - Leases. The provisions of this Statement are required to be implemented for the 2020 financial reporting period.

- GASB 88 - Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements. The provisions of this statement are required to be implemented in the 2019 reporting period.

- GASB 89 - Accounting for Interest Costs Incurred before the End of a Construction Period. The provisions of this statement are required to be implemented in the 2020 reporting period.

- GASB 90 - Majority Equity Interests. An Amendment to GASB Statements No. 14 and No. 61. The provisions of this statement are required to be implemented for the 2019 financial reporting period.

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REQUIRED SUPPLEMENTARY INFORMATION

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MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System- Defined Benefit Pension Plan
Schedule of the Utility's Information on the Net Pension Liability

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Net Pension Liability	Utility's Proportionate Share of the Net Pension Liability	State of Alaska's Proportionate Share of the Net Pension Liability	Total Utility Net Pension Liability	Utility's Covered Payroll	Utility's Proportionate Share of the Net Pension Liability as a percentage of Payroll	Plan Fiduciary Net Position as a Percentage of the Total Pension Liability
2017	2017	0.23737%	$ 12,270,893	$ 4,571,641	$ 16,842,534	$ 6,874,310	178.50%	63.37%
2016	2016	0.27003%	15,093,423	1,901,832	16,995,255	7,069,090	213.51%	59.55%
2015	2015	0.21637%	10,494,008	2,810,753	13,304,761	6,832,003	153.60%	63.96%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Required Supplementary Information
Public Employees Retirement System - Defined Benefit Pension Plan
Schedule of Utility Contributions

Year Ended December 31,	Measurement Period Ended June 30,	Utility's Proportion of the Contractually Required Contribution	Contributions Relative to the Contractually Required Contribution	Contribution Deficiency (Excess)	Utility's Covered Payroll	Contributions as a Percentage of Covered Payroll
2017	2017	$ 940,338	$ 940,338	$ -	$ 7,051,257	13.336%
2016	2016	854,217	854,217	-	7,204,870	11.856%
2015	2015	767,929	767,929	-	6,991,594	10.984%

See accompanying notes to Required Supplementary Information.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
International Brotherhood of Electrical Workers (IBEW) - Defined Benefit Pension Plan
Schedule of Utility Contributions
Last 10 Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Contractually required contribution	$ 3,272,545	3,396,484	3,059,562	2,642,768	2,637,978	2,778,451	2,649,741	2,560,129	2,560,894	2,324,707
Contributions in relation to the contractually required contribution	3,272,545	3,396,484	3,059,562	2,642,768	2,637,978	2,778,451	2,649,741	2,560,129	2,560,894	2,324,707
Contribution deficiency (excess)	$ -	-	-	-	-	-	-	-	-	-
Utility's covered-employee payroll	$ 21,544,626	21,965,741	20,773,482	19,554,891	19,679,139	19,988,244	18,622,524	17,589,819	16,854,932	15,402,081
Contribution as a percentage of covered-employee payroll	15.19%	15.46%	14.73%	13.51%	13.40%	13.90%	14.23%	14.55%	15.19%	15.09%

See accompanying notes to Required Supplementary Information.

Pension Disclosures

Public Employees Retirement System - Defined Benefit Plan

In accordance with GASB Statement No. 82, "Covered Payroll" is defined as payroll on which contributions to the pension plan are based. Because a portion of the Municipality's contributions to the Plan (the DBUL) are based on Defined Contribution Wages, covered payroll reported here includes all PERS participating wages (both Defined Benefit and Defined Contribution).

Both pension tables are intended to present 10 years of information. Additional years' information will be added to the schedules as it becomes available.

Schedule of Utility's Information on the Net Pension Liability

- This table is presented based on the Plan measurement date. For December 31, 2017, the Plan measurement date is June 30, 2017.
- There were no changes in benefit terms from the prior measurement period.
- There were no changes in assumptions from the prior measurement period.
- There were no changes in valuation method from the prior measurement period.
- There were no changes in the allocation methodology from the prior measurement period. The measurement period ended June 30, 2017 allocated the net pension liability based on the present value of contributions for fiscal year 2019 through 2039, as determined by projections based on the June 30, 2016 actuarial valuation.

Schedule of Utility Contributions

- This table is based on the Utility's contributions for each year presented. A portion of these contributions are included in the plan measurement results, while a portion of the contributions are reported as a deferred outflow of resources on the December 31, 2017 statement of net position.

International Brotherhood of Electrical Workers (IBEW) Defined Benefit Pension Plan

Schedule of Utility Contributions

- This table presents the Utility contributions for each of the last ten years based on calendar year contributions.
- In accordance with GASB Statement 78, "Covered Payroll" is defined as payroll on which contributions to the pension plan are based.

STATISTICAL SECTION

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Net Position by Components
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Invested in capital assets (net of related debt)	$ 201,055,297	215,402,069	219,019,326	232,279,391	224,974,557	241,055,196	202,173,253	166,889,451	143,468,713	169,633,315
Restricted for debt service	71,082	269,541	802,827	590,403	1,511,334	1,550,681	33,687,889	34,582,450	34,479,471	27,503,462
Restricted for interim rate escrow requirement	-	-	-	-	-	-	-	2,048,840	-	-
Restricted for operations	14,235,000	13,200,000	12,450,000	10,100,000	9,600,000	9,600,000	10,625,000	9,400,000	8,600,000	8,000,000
Unrestricted	54,095,867	25,694,823	16,500,688	12,534,565	11,790,270	(4,131,606)	(6,887,599)	20,876,436	43,792,529	18,580,433
Total net position by components	$ 269,457,246	254,566,433	248,772,841	255,504,359	247,876,161	248,074,271	239,598,543	233,797,177	230,340,713	223,717,210

The Utility has prepared independent financial statements based on net position in 2014-2017. Prior to that, the Utility prepared financial statements based upon net assets from 2008-2013.
The prior years statistics have not been restated.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Change in Net Position
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Expenses:										
Production	$ 84,409,875	75,100,243	70,435,716	52,745,264	46,245,591	49,569,470	57,032,547	48,356,518	40,096,863	36,251,077
Transmission	1,160,932	937,495	1,010,600	1,277,246	659,063	1,146,681	551,785	517,332	560,833	512,068
Distribution	11,609,032	11,787,913	10,868,143	10,504,929	10,138,088	9,124,625	8,352,505	7,709,097	8,378,660	8,893,177
Customer service and sales	4,285,142	4,528,685	4,022,991	3,987,004	3,939,887	4,166,844	4,171,770	4,125,907	4,053,676	3,499,192
Administrative and general	11,044,068	11,373,116	10,689,722	11,001,466	9,590,291	9,610,553	8,808,753	8,456,134	9,446,731	9,551,094
Taxes other than income	1,367,440	1,737,906	986,159	981,545	988,586	849,320	610,940	548,118	363,284	587,813
Regulatory debits (credits)	(4,028,641)	6,359,769	5,923,949	(2,264,613)	(7,121,479)	(6,163,585)	3,432,854	7,556,737	4,191,550	(6,872,354)
Depreciation	32,453,517	31,634,639	29,643,901	30,700,970	31,184,140	26,877,295	25,948,744	26,795,802	26,250,618	25,932,754
Nonoperating expenses	22,768,624	15,507,360	17,904,982	12,900,641	11,584,587	6,980,851	11,674,152	16,093,605	10,626,438	11,972,783
	165,069,989	158,967,126	151,486,163	121,834,452	107,208,754	102,162,054	120,584,050	120,159,250	103,968,653	90,327,604
Operating revenues:										
Residential sales	26,125,850	22,260,329	21,972,135	21,435,044	18,480,248	17,221,156	18,732,524	18,576,036	17,973,827	15,375,276
Commercial and industrial sales	122,670,602	106,258,842	102,566,471	98,470,914	80,954,769	70,690,478	81,243,174	81,223,012	76,949,102	62,405,290
Military sales	17,452,871	15,437,345	14,525,488	13,422,166	11,814,277	11,827,304	15,381,907	15,687,195	13,927,149	10,607,417
Sales for resale	23,344,433	15,343,153	21,890,648	7,391,906	3,652,081	16,408,646	17,053,859	9,434,212	8,522,078	16,137,134
Other operating revenues	(5,169,343)	7,852,729	3,181,925	(812,298)	2,066,984	3,231,506	2,006,188	4,642,456	1,247,914	2,682,686
Operating revenues	184,424,413	167,152,398	164,136,667	139,907,732	116,968,359	119,379,090	134,417,652	129,562,911	118,620,070	107,207,803
Nonoperating revenues	4,868,051	3,583,438	2,936,315	3,085,196	1,851,454	3,594,606	3,938,876	5,139,469	1,778,202	839,102
Total revenues	189,292,464	170,735,836	167,072,982	142,992,928	118,819,813	122,973,696	138,356,528	134,702,380	120,398,272	108,046,905
Income before transfers	24,222,475	11,768,710	15,586,819	21,158,476	11,611,059	20,811,642	17,772,478	14,543,130	16,429,619	17,719,301
Transfer to/from other funds:										
Municipal Utility Service Assessment	(9,331,662)	(5,983,574)	(7,538,022)	(7,381,413)	(5,539,711)	(5,549,734)	(5,375,710)	(5,072,546)	(4,404,760)	(4,314,224)
Transfers to other funds	-	-	(8,579)	(326,886)	(250,967)	-	-	-	-	(1,500)
Transfers from other funds	-	8,456	-	-	-	-	-	-	-	93,205
Dividend	-	-	(7,028,943)	(5,821,979)	(6,018,491)	(6,786,180)	(6,595,402)	(6,014,120)	(5,401,356)	(5,192,306)
Special item	-	-	-	-	-	-	-	-	-	920,985
Changes in net position	$ 14,890,813	5,793,592	1,011,275	7,628,198	(198,110)	8,475,728	5,801,366	3,456,464	6,623,503	9,225,461

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Capital Assets
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Capital assets:										
Steam production	$ 242,833,584	242,706,892	100,399,485	100,313,798	100,499,831	27,355,731	27,255,483	26,034,220	25,696,521	24,724,449
Hydraulic production	6,932,007	5,808,598	5,808,598	5,685,191	5,575,733	5,575,733	5,540,828	5,413,702	5,284,699	5,187,198
Other production	309,370,891	302,412,281	193,263,836	185,758,015	185,638,532	143,436,524	142,440,360	136,243,299	136,017,416	131,473,870
Transmission plant	76,759,366	73,953,864	53,003,063	50,840,731	49,638,097	38,519,353	36,105,088	36,330,641	36,069,822	32,348,812
Distribution plant	280,188,291	269,997,456	261,351,063	253,135,670	244,862,546	229,933,248	219,582,019	208,302,074	197,667,947	184,952,002
General plant	43,877,572	42,912,800	42,116,790	40,586,517	38,862,644	36,182,885	33,340,550	32,923,647	30,726,421	34,210,699
Miscellaneous intangible plant	15,116,282	10,283,951	9,439,191	8,135,695	7,966,618	7,657,794	5,790,385	5,745,486	2,064,007	1,993,026
	975,077,993	948,075,842	665,382,026	644,455,617	633,044,001	488,661,268	470,054,713	450,993,069	433,526,833	414,890,056
Intangible plant	15,272,228	15,272,228	15,272,228	15,272,227	15,207,522	14,819,398	12,114,070	12,114,070	12,114,070	12,114,070
Other utility plant	-	-	-	741,167	741,167	741,167	741,167	741,167	741,167	741,167
Gas production	345,231,780	345,231,780	234,240,102	231,845,379	223,871,525	201,256,373	173,153,637	172,552,815	170,211,951	160,824,049
Total capital assets	1,335,582,001	1,308,579,850	914,894,356	892,314,390	872,864,215	705,478,206	656,063,587	636,401,121	616,594,021	588,569,342
Less accumulated depreciation for:										
Steam production	21,801,329	14,232,714	21,857,750	17,534,028	13,148,561	10,503,284	9,456,871	9,069,877	7,968,921	7,383,973
Hydraulic production	2,910,468	2,748,686	2,589,497	2,432,615	2,277,396	2,123,878	1,964,253	1,808,056	1,654,369	1,504,704
Other production	87,475,934	76,537,234	80,824,117	77,785,128	71,878,823	67,305,379	71,768,133	67,217,604	63,592,830	64,196,155
Transmission plant	17,742,318	16,586,098	15,559,845	14,866,936	14,279,448	13,555,499	12,929,380	12,668,386	12,345,716	11,962,640
Distribution plant	97,504,590	91,456,381	87,378,398	86,107,037	83,291,260	81,837,910	76,775,617	72,739,763	71,259,721	68,782,580
General plant	22,855,376	21,182,334	20,683,576	19,531,321	18,323,696	18,019,435	16,672,643	15,538,350	15,418,038	20,666,861
Miscellaneous intangible plant	11,393,594	9,850,263	8,617,566	7,270,959	5,785,215	4,406,987	3,061,171	1,909,133	997,475	612,835
	261,683,609	232,593,710	237,510,749	225,528,024	208,984,399	197,752,372	192,628,068	180,951,169	173,237,070	175,109,748
Intangible plant	12,661,781	12,556,509	12,253,324	11,744,249	11,235,363	10,734,809	10,300,948	9,897,146	9,493,344	9,089,542
Other utility plant	-	-	-	741,167	741,167	741,167	741,167	741,167	741,167	741,167
Gas production	194,387,360	182,975,820	164,257,080	146,744,614	130,649,710	116,553,669	100,919,949	88,736,800	75,095,030	59,100,892
Total accumulated depreciation	468,732,750	428,126,039	414,021,153	384,758,054	351,610,639	325,782,017	304,590,132	280,326,282	258,566,611	244,041,349
Total capital assets, net	866,849,251	880,453,811	500,873,203	507,556,336	521,253,576	379,696,189	351,473,455	356,074,839	358,027,410	344,527,993
Construction work in progress:										
Electric	22,643,309	15,783,204	258,154,569	183,164,569	71,387,105	152,887,160	104,477,262	50,665,960	20,759,469	14,636,770
Gas	314,131	-	151,583	1,707,078	295,199	20,418,060	31,882,134	10,281,252	2,957,087	546,141
Total construction work in progress	22,957,440	15,783,204	258,306,152	184,871,647	71,682,304	173,305,220	136,359,396	60,947,212	23,716,556	15,182,911
Total construction work in progress and net capital assets	$ 889,806,691	896,237,015	759,179,355	692,427,983	592,935,880	553,001,409	487,832,851	417,022,051	381,743,966	359,710,904

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Comparative Operating Revenue Relationships
Last Ten Fiscal Years

		2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Residential sales:											
Average number of customers		24,680	24,678	24,555	24,429	24,463	24,443	24,302	24,206	24,139	24,108
Total kilowatt-hour sales		127,375,339	127,731,695	130,805,337	133,411,070	139,732,855	146,789,292	143,843,977	143,472,478	147,643,203	147,725,244
Total dollar revenue	$	26,125,850	22,260,329	21,972,135	21,435,044	18,480,248	17,221,156	18,732,524	18,576,036	17,973,827	15,375,276
Average annual kilowatt-hour per customer		5,161	5,176	5,327	5,461	5,712	6,005	5,919	5,927	6,116	6,128
Average annual bill per customer	$	1,059	902	895	877	755	705	771	767	745	638
Average revenue per kilowatt-hour sold		0.2052	0.1743	0.1680	0.1606	0.1323	0.1173	0.1303	0.1294	0.1218	0.1041
Commercial and industrial sales:											
Average number of customers		6,388	6,398	6,373	6,358	6,319	6,300	6,297	6,271	6,263	6,239
Total kilowatt-hour sales		688,715,880	712,231,709	722,420,813	729,977,884	742,080,706	754,621,548	753,639,798	749,946,176	760,449,972	754,541,810
Total dollar revenue	$	119,296,069	105,104,185	101,541,955	97,502,022	80,294,932	70,118,871	80,495,645	80,415,527	76,174,620	61,893,042
Average annual kilowatt-hour per customer		107,814	111,321	113,356	114,813	117,436	119,781	119,682	119,590	121,419	120,940
Average annual bill per customer	$	18,675	16,428	15,933	15,335	12,707	11,130	12,783	12,823	12,163	9,920
Average revenue per kilowatt-hour sold		0.1732	0.1476	0.1406	0.1336	0.1082	0.0929	0.1068	0.1072	0.1002	0.0820
Water diversion compensation	$	1,248,071	1,154,656	1,024,516	968,892	659,837	571,607	747,529	807,485	774,482	512,248
Military:											
Total kilowatt-hour sales		144,968,449	147,440,533	146,817,935	145,055,072	160,954,213	194,549,942	209,515,273	210,847,451	203,017,515	211,684,628
Total dollar revenue	$	17,452,871	15,437,345	14,525,488	13,422,166	11,814,277	11,827,304	15,381,907	15,687,195	13,927,149	10,607,417
Sales for resale:											
Total kilowatt-hour sales		387,688,000	213,901,000	257,893,000	94,966,698	56,954,000	157,854,000	185,375,000	121,314,000	107,788,000	214,333,000
Total dollar revenue	$	23,344,433	15,343,153	21,890,648	7,391,906	3,652,081	16,408,646	17,053,859	9,434,212	8,522,078	16,137,134
Unmetered street lights:											
Total kilowatt-hour sales		4,430,339	4,475,018	4,452,480	4,340,094	4,702,030	4,704,154	4,643,571	4,514,322	4,853,411	4,799,970
Total dollar revenue	$	2,126,462	1,684,211	1,662,816	1,622,449	1,348,286	1,220,224	1,258,236	1,235,236	1,211,707	1,157,113
Total sales:											
Total kilowatt-hour sales		1,353,178,007	1,205,779,955	1,262,389,565	1,107,750,818	1,104,423,804	1,258,518,936	1,297,017,619	1,230,094,427	1,223,752,101	1,333,084,652
Total sales revenue	$	189,593,756	160,983,879	162,617,558	142,342,479	116,249,661	117,367,808	133,669,700	126,155,691	118,583,863	105,682,230
Average retail revenue per kilowatt-hour sold: (Residential sales and Commercial & industrial sales)											
Total dollar revenue	$	145,421,919	127,364,514	123,514,090	118,937,066	98,775,180	87,340,027	99,228,169	98,991,563	94,148,447	77,268,318
Total kilowatt-hour sales		816,091,219	839,963,404	853,226,150	863,388,954	881,813,561	901,410,840	897,483,775	893,418,654	908,093,175	902,267,054
Average retail revenue per kilowatt-hour sold		0.1782	0.1516	0.1448	0.1378	0.1120	0.0969	0.1106	0.1108	0.1037	0.0856

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2017	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 13,810,920	121,123,845
Municipality of Anchorage	6,244,068	21,997,754
Providence Alaska Medical	4,527,732	29,313,454
Anchorage School District	4,144,490	21,900,552
State of Alaska	4,055,188	24,489,039
Fort Richardson	3,641,951	23,844,604
University of Alaska, Anchorage	3,075,322	18,469,251
University of Alaska	2,762,581	16,788,893
Providence Health System	2,742,328	16,584,283
Alaska Native Tribal Health Consortium	2,625,088	16,570,118

	2016	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 12,249,880	121,923,613
Municipality of Anchorage	5,010,301	25,943,896
Providence Alaska Medical	4,047,395	30,672,310
State of Alaska	3,601,515	25,281,432
Anchorage School District	3,567,374	22,742,140
Fort Richardson	3,187,464	25,516,920
University of Alaska, Anchorage	2,583,129	18,519,071
University of Alaska	2,409,761	17,348,160
Providence Health System	2,384,436	17,182,319
Alaska Native Tribal Health Consortium	2,212,302	16,300,831

	2015	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,714,725	123,925,931
Municipality of Anchorage	4,906,357	26,544,546
Providence Alaska Medical	3,765,947	29,916,508
State of Alaska	3,559,141	26,353,330
Anchorage School District	3,520,203	23,392,075
Fort Richardson	2,810,763	22,892,004
University of Alaska, Anchorage	2,461,696	18,359,501
University of Alaska	2,304,264	17,427,455
Providence Health System	2,197,364	16,644,299
Alaska Native Tribal Health Consortium	2,172,315	16,242,233

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2014	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 11,017,465	125,613,900
Municipality of Anchorage	4,415,594	24,172,965
Providence Alaska Medical	3,530,551	29,596,430
State of Alaska	3,255,191	25,479,576
Anchorage School District	3,106,621	21,463,838
Fort Richardson	2,404,701	19,441,172
University of Alaska, Anchorage	2,177,227	17,079,887
Providence Health System	1,945,608	15,541,320
University of Alaska	1,913,342	15,008,522
Alaska Native Tribal Health Consortium	1,832,379	15,140,657

	2013	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,226,223	131,043,824
Anchorage School District	2,897,648	24,777,425
Municipality of Anchorage	3,824,941	26,282,712
State of Alaska	2,803,076	27,544,890
Providence Alaska Medical	2,629,984	28,699,997
Fort Richardson	2,588,055	29,910,389
University of Alaska	2,072,531	20,064,980
Providence Health System	1,783,576	17,591,484
Alaska Native Tribal Health Consortium	1,589,389	16,216,071
Galen Hospital Alaska, Inc	1,571,321	16,211,245

	2012	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 8,097,877	135,878,731
Fort Richardson	3,729,428	58,671,211
Municipality of Anchorage	3,422,563	26,655,434
Anchorage School District	2,655,271	26,608,898
State of Alaska	2,492,450	28,556,399
Providence Alaska Medical	2,234,908	29,596,617
University of Alaska	1,793,961	20,506,774
Providence Health System	1,514,000	17,642,498
Galen Hospital Alaska, Inc	1,386,848	16,893,051
Alaska Native Tribal Health Consortium	1,313,019	15,929,544

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2011	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,921,072	135,333,281
Fort Richardson	5,460,835	74,181,992
Municipality of Anchorage	3,809,602	27,353,371
Providence Alaska Medical	3,116,712	29,971,840
Anchorage School District	3,015,951	26,844,664
State of Alaska	2,752,681	26,966,050
University of Alaska	2,066,234	20,226,113
Providence Health System	1,727,491	17,114,796
Galen Hospital Alaska, Inc	1,629,192	16,791,861
Alaska Native Tribal Health Consortium	1,518,934	15,702,915

	2010	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,991,880	134,772,525
Fort Richardson	5,695,316	76,074,926
Municipality of Anchorage	3,744,757	26,775,275
Anchorage School District	3,066,378	27,288,755
Providence Alaska Medical	2,871,643	29,775,325
State of Alaska	2,764,053	26,965,173
University of Alaska	2,042,255	19,973,125
Galen Hospital Alaska, Inc	1,655,862	16,844,949
Providence Health System	1,529,925	15,062,395
Alaska Native Tribal Health Consortium	1,428,740	14,679,960

	2009	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 9,053,368	132,512,540
Fort Richardson	4,873,781	70,504,975
Municipality of Anchorage	3,565,407	27,479,484
Anchorage School District	3,003,112	28,837,796
Providence Alaska Medical	2,661,493	29,740,551
State of Alaska	2,638,850	27,613,800
University of Alaska	1,942,120	20,475,951
Galen Hospital Alaska, Inc	1,573,382	17,169,527
Providence Health System	1,346,611	14,259,674
Alaska Native Tribal Health Consortium	1,296,731	14,458,413

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Top Ten Customers By Revenue
Last Ten Fiscal Years

	2008	
Customer	Revenue ($)	Sales (kWh)
Elmendorf Air Force Base	$ 6,749,206	135,427,252
Fort Richardson	3,858,211	76,257,376
Municipality of Anchorage	3,230,021	28,669,424
Anchorage School District	2,460,927	28,897,407
State of Alaska	2,084,279	27,150,535
Providence Alaska Medical	2,080,667	29,088,684
University of Alaska	1,582,133	20,471,933
United States Government	1,318,939	17,100,335
Galen Hospital Alaska, Inc	1,191,099	16,127,466
Providence Health System	1,023,623	13,434,937

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Summary

Effective date	Permanent 04/20/18	Interim 02/15/17	Permanent 07/16/15	Interim 10/24/13	Interim 03/01/13
Base cost of power ($/kWh)	-	-	-	-	-
Residential:					
Schedule 11					
Customer charge ($/month)	13.62	6.56	6.56	6.56	6.56
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.15274	0.14738	0.10734	0.10734	0.08634
Commercial:					
Schedule 21 - small commercial					
Customer charge ($/month)	30.46	12.88	12.88	12.88	12.88
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.11878	0.14161	0.10314	0.10314	0.08296
Schedule 22 - large commercial at secondary voltage					
Customer charge ($/month)	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW)	44.53	23.29	16.96	16.96	13.64
Energy charge ($/kWh)	0.00498	0.06630	0.04829	0.04829	0.03884
Schedule 23 - large commercial at primary voltage					
Customer charge ($/month)	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW)	43.10	26.18	19.07	19.07	15.34
Energy charge ($/kWh)	0.00488	0.06244	0.04548	0.04548	0.03658
Schedule 25 - replacement energy, AWWU					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.02561	0.03497	0.02547	0.02547	0.02049
Schedule 27 - interruptible power at secondary voltage					
Customer charge ($/month)	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.37673	0.06630	0.04829	0.04829	0.03884
Schedules 31, 32, 33 - general service seasonal at secondary voltage					
Customer charge ($/month) - winter	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW) - winter	-	-	-	-	-
Energy charge ($/kWh) - winter	0.11878	0.14161	0.10314	0.10314	0.08296
Customer charge ($/month) - summer	92.61	44.15	44.15	44.15	44.15
Demand charge ($/kW) - summer	44.53	23.29	16.96	16.96	13.64
Energy charge ($/kWh) - summer	0.00498	0.06630	0.04829	0.04829	0.03884
Schedules 34, 35, 36 - general service seasonal at primary voltage					
Customer charge ($/month) - winter	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW) - winter	-	-	-	-	-
Energy charge ($/kWh) - winter	0.09355	0.13502	0.09834	0.09834	0.07910
Customer charge ($/month) - summer	619.42	159.55	159.55	159.55	159.55
Demand charge ($/kW) - summer	43.10	26.18	19.07	19.07	15.34
Energy charge ($/kWh) - summer	0.00488	0.06244	0.04548	0.04548	0.03658
Area lighting/street lighting:					
Schedules 41/60 ($/month) (150 watt luminaire)	37.78	35.15	25.60	25.60	20.59
Schedules 42/61 ($/month) (175 watt luminaire)	39.74	36.97	26.93	26.93	21.66
Schedules 43/62 ($/month) (250 Watt luminaire)	44.81	41.70	30.37	30.37	24.43
Schedules 44/63 ($/month) (400 watt luminaire)	55.69	51.82	37.74	37.74	30.36
Schedules 45/64 ($/month) (1,000 watt luminaire)	101.61	94.55	68.86	68.86	55.39

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Summary

	Permanent	Interim	Permanent	Interim	Interim
Effective date	04/20/18	02/15/17	07/16/15	10/24/13	03/01/13
Military:					
Schedule 700 - interruptible service - Ft. Richardson - at primary voltage					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.07245	0.05368	0.03910	0.03910	0.03145
Schedule 750 - interruptible service - Elmendorf AFB - at primary voltage					
Customer charge ($/month)	-	-	-	-	-
Demand charge ($/kW)	-	-	-	-	-
Energy charge ($/kWh)	0.08428	0.06244	0.04548	0.04548	0.03658
Schedule 760 - limited all requirements service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Demand charge ($/kW)	45.43	17.36	12.64	12.64	10.17
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829
Schedule 770 - partial requirements service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Baseload demand charge ($/kW)	39.66	9.44	6.87	6.87	5.53
Peaking demand charge ($/kW)	39.66	21.42	15.60	15.60	12.55
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829
Schedule 780 - seasonal replacement service at primary voltage					
Customer charge ($/month)	668.42	159.55	159.55	159.55	159.55
Replacement capacity charge($/kW)	39.66	9.44	6.87	6.87	5.53
Excess demand charge ($/kW)	39.66	21.42	15.60	15.60	12.55
Energy charge ($/kWh)	0.00488	0.04829	0.03517	0.03517	0.02829

(1) Base cost of power ($/kWh) is not included in the energy rates for 10/01/2011 and is now included in the cost of power adjustment (COPA).

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Typical Monthly Bill Comparison
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Residential:										
Municipal Light and Power (ML&P)	$ 115.02	94.84	91.48	88.07	72.78	63.42	71.07	70.91	67.14	61.49
Chugach Electric Association (CEA)	97.55	100.87	96.63	89.78	80.77	81.89	79.23	74.17	86.93	77.70
Matanuska Electric Association Inc. (MEA)	118.81	110.11	109.70	94.46	85.60	86.61	85.56	78.21	91.70	79.26
Homer Electric Association (HEA)	139.77	137.34	137.60	131.93	113.14	108.40	115.82	96.22	111.49	93.12
Golden Valley Electric Association (GVEA)	133.44	124.36	120.88	128.94	128.64	137.98	121.05	116.29	94.10	115.69
Small commercial:										
ML&P	280.89	231.72	223.17	214.47	176.51	153.22	172.77	172.48	162.97	148.58
CEA	198.58	207.12	199.05	187.71	170.12	177.16	170.22	157.06	198.29	177.20
MEA	286.27	269.25	268.33	229.63	207.14	209.80	207.13	188.46	222.87	191.22
HEA	333.38	327.48	328.80	314.29	266.38	254.22	273.49	224.61	263.83	217.23
GVEA	313.69	290.57	281.79	302.40	301.70	325.55	282.51	270.41	217.40	273.54
Large commercial:										
Secondary:										
ML&P	7,250.48	6,001.67	5,745.19	5,484.18	4,419.30	3,801.49	4,397.47	4,399.98	4,122.93	3,691.11
CEA	5,624.11	5,880.17	5,630.91	5,268.47	4,722.87	4,916.54	4,715.59	4,311.27	5,317.59	4,590.04
MEA	7,344.33	6,751.96	6,775.04	5,672.57	5,021.80	5,147.65	5,073.38	4,527.95	5,601.53	4,656.74
HEA	9,036.26	8,991.22	9,064.48	8,651.25	7,228.33	6,890.71	7,786.51	6,314.29	7,479.96	6,080.30
GVEA	8,055.39	7,365.98	7,155.64	7,814.87	7,824.12	8,588.88	7,299.38	6,967.65	5,506.23	7,230.27
Primary:										
ML&P	41,765.37	34,752.86	33,201.74	31,623.26	25,421.68	21,806.96	25,428.81	25,472.33	23,819.64	21,208.14
CEA	32,403.60	33,943.46	32,511.01	30,425.12	27,233.03	28,524.86	27,003.61	24,526.95	29,964.97	25,499.07
MEA	36,337.67	42,034.81	42,127.05	35,408.22	31,407.40	32,208.29	31,737.59	28,412.35	34,859.93	29,140.05
HEA	37,578.59	36,637.78	37,961.74	36,426.86	28,413.23	27,513.54	38,928.11	30,271.26	37,878.94	29,386.05
GVEA	47,067.48	42,906.03	41,735.07	45,801.46	45,927.60	50,632.17	42,919.67	38,864.16	30,500.45	41,264.32

Billing determinants

	Typical customer bill	
Type of service:	kWh	kW
Residential	550	n/a
Small commercial	1,400	n/a
Large commercial, secondary	42,000	100
Large commercial, primary	254,000	500

Monthly bills include customer charge, energy charge, demand charge (where applicable), cost of power adjustment (COPA), and regulatory cost charge (RCC).
At the beginning of each quarter a typical monthly bill is calculated using rates in effect for that quarter. At the end of the calendar year a simple average of the four quarters is computed and represents a typical monthly bill for the year.

Average rates are based on current typical customer bill kWh and kW. Prior years' rates have been restated to reflect a more accurate typical customer bill kWh and kW.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Rate Comparison

	Average in Cents/kWh*									
	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Residential:										
ML&P	20.91	17.24	16.63	16.01	13.23	11.53	12.92	12.89	12.21	11.18
CEA	17.74	18.34	17.57	16.32	14.69	14.89	14.41	13.49	15.81	14.13
MEA	21.60	20.02	19.95	17.17	15.56	15.75	15.56	14.22	16.67	14.41
HEA	25.41	24.97	25.02	23.99	20.57	19.71	21.06	17.49	20.27	16.93
GVEA	24.26	22.61	21.98	23.44	23.39	25.09	22.01	21.14	17.11	21.04
Small commercial:										
ML&P	20.06	16.55	15.94	15.32	12.61	10.94	12.34	12.32	11.64	10.61
CEA	14.18	14.79	14.22	13.41	12.15	12.65	12.16	11.22	14.16	12.66
MEA	20.45	19.23	19.17	16.40	14.80	14.99	14.80	13.46	15.92	13.66
HEA	23.81	23.39	23.49	22.45	19.03	18.16	19.53	16.04	18.84	15.52
GVEA	22.41	20.75	20.13	21.60	21.55	23.25	20.18	19.32	15.53	19.54
Large commercial:										
Secondary:										
ML&P	17.26	14.29	13.68	13.06	10.52	9.05	10.47	10.48	9.82	8.79
CEA	13.39	14.00	13.41	12.54	11.24	11.71	11.23	10.26	12.66	10.93
MEA	17.49	16.08	16.13	13.51	11.96	12.26	12.08	10.78	13.34	11.09
HEA	21.51	21.41	21.58	20.60	17.21	16.41	18.54	15.03	17.81	14.48
GVEA	19.18	17.54	17.04	18.61	18.63	20.45	17.38	16.59	13.11	17.21
Primary:										
ML&P	16.44	13.68	13.07	12.45	10.01	8.59	10.01	10.03	9.38	8.35
CEA	12.76	13.36	12.80	11.98	10.72	11.23	10.63	9.66	11.80	10.04
MEA	14.31	16.55	16.59	13.94	12.37	12.68	12.50	11.19	13.72	11.47
HEA	14.79	14.42	14.95	14.34	11.19	10.83	15.33	11.92	14.91	11.57
GVEA	18.53	16.89	16.43	18.03	18.08	19.93	16.90	15.30	12.01	16.25

Average rate comparisons, when expressed in cents per kWh, are derived by dividing the typical monthly bill by the kWh's (See Typical Monthly Bill Comparison) used to calculate the bill for each class and multiplying the result by 100 to convert to cents per kWh.

Average rates are based on current typical customer bill kWh and kW. Prior years' rates have been restated to reflect a more accurate typical customer bill kWh and kW.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)

Bond Debt

Principal and Interest (cash basis)

	Senior lien electric revenue bonds		
Year	Principal	Interest	Total
2018	$ 7,865,000	17,313,097	25,178,097
2019	7,730,000	16,950,747	24,680,747
2020	8,075,000	16,603,147	24,678,147
2021	8,410,000	16,268,347	24,678,347
2022	8,760,000	15,917,897	24,677,897
2023-2027	50,570,000	72,518,785	123,088,785
2028-2032	63,490,000	56,987,657	120,477,657
2033-2037	79,780,000	36,583,462	116,363,462
2038-2042	66,840,000	13,095,887	79,935,887
2043-2044	21,850,000	1,319,600	23,169,600
	$ 323,370,000	263,558,626	586,928,626

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Schedule of Revenue Bond Coverage
Last Ten Fiscal Years

Fiscal Year	Revenue (1)(2)	Operating Expenses (3)	Net Revenue Available for Debt Service	Debt Service Requirement (accrual basis) Principal (4)	Interest (2)(4)	Total Debt Service	Coverage (5)
2017	$ 186,859,566	$ 119,179,510	$ 67,680,056	$ 7,520,000	$ 15,197,731	$ 22,717,731	***2.98***
2016	168,290,963	117,808,701	50,482,262	7,465,000	15,561,997	23,026,997	***2.19***
2015	164,652,279	111,475,302	53,176,977	7,440,000	15,868,460	23,308,460	***2.28***
2014	140,578,329	85,614,254	54,964,075	17,910,000	10,719,674	28,629,674	***1.92***
2013	116,439,242	69,979,738	46,459,504	17,085,000	10,684,851	27,769,851	***1.67***
2012	122,973,354	73,853,642	49,119,712	16,915,000	13,953,484	30,868,484	***1.59***
2011	138,326,743	88,336,864	49,989,879	16,945,000	14,969,376	31,914,376	***1.57***
2010	134,571,665	82,342,389	52,229,276	16,995,000	15,974,962	32,969,962	***1.58***
2009	120,484,857	71,496,357	48,988,500	17,270,000	9,460,410	26,730,410	***1.83***
2008	108,120,323	56,737,791	51,382,532	17,295,000	9,775,653	27,070,653	***1.90***

(1) Excludes interest charged to construction and interest restricted for construction.
(2) Excludes Federal subsidy for 2013 through 2017
(3) Includes Municipal Service Assessment per Municipal Ordinance AO 83-58 and excludes depreciation.
(4) 2014 Principal and Interest do not include the debt service for 1996 Senior Lien Bonds defeased during the year.
(5) The required minimum revenue bond coverage is 1.35 and the all-debt minimum coverage is 1.10.
Notes payable are not reflected on this schedule. If it were included, all-debt coverage for fiscal years 2017 and 2016 would be 1.92 and 1.45, respectively.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Statement of Net Position Ratios
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Current ratio	2.90	0.43	0.47	0.94	0.37	0.67	3.54	3.72	4.72	2.87

This ratio is a measure of the Utility's ability to meet short-term obligations.
The current ratio is calculated by dividing current assets by current liabilities.

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Long-term debt/gross plant	28 / 72	28 / 72	29 / 71	27 / 73	25 / 75	24 / 76	23 / 77	27 / 73	30 / 70	21 / 79

This ratio provides the gross plant value represented by long-term debt.
It is an indication of how much leverage has been utilized in acquiring plant assets.

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Debt/Equity (Net Position)	66 / 34	67 / 33	65 / 35	59 / 41	56 / 44	52 / 48	50 / 50	52/48	54 / 46	42 / 58

This ratio expresses the relationship of gross debt to net position as components of the total capital structure (excluding net pension liability and including commercial paper).

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Return on net position (excluding dividend and special item)	5.85%	2.33%	3.15%	5.43%	2.35%	6.37%	5.30%	4.11%	5.38%	6.29%

This ratio is a measure of the return received on net position.
The return on net position is calculated by dividing the change in net position, (excluding dividend and special item) by net position.

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Operating margin	22.84%	14.17%	18.62%	22.14%	18.25%	20.27%	18.98%	19.68%	21.31%	26.91%

The operating margin ratio expresses the percentage of each dollar of operating revenue that represents operating income. The ratio is calculated as operating income divided by operating revenue.

The utility started preparing independent financial statements based on net position in 2013 and based on net assets from 2007 to 2012.
The prior years have not been restated in the statistical section.

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
As of December 31, 2017
Base Ratings by Generation Units

		Base rating		Nameplate
Type	Unit no.	30F (MW)	ISO (MW)	capacity (KVA)
Combustion turbine	3	32.9	29.3	48,941
Combustion turbine	4	33.6	31.1	31,765
Combustion turbine	7	81.8	74.4	110,556
Combustion turbine	8	85.0	77.3	102,941
Combustion turbine	9	48.9	48.5	71,000
Combustion turbine	10	48.9	48.5	71,000
Steam turbine	11	28.9	28.9	36,000
Sub-total		360.0	338.0	472,203
Hydro-turbine (Eklutna)	1	22.2	22.2	22,222
Hydro-turbine (Eklutna)	2	22.2	22.2	22,222
Sub-total		404.4	382.4	516,647
Steam Turbine (SPP)	10	57.5	38.1	67,647
Cumbustion Turbine (SPP)	11	47.6	40.2	57,352
Cumbustion Turbine (SPP)	12	47.6	40.2	57,352
Cumbustion Turbine (SPP)	13	47.6	40.2	57,352
Total		604.7	541.1	756,350
ML&P units		360.0	338.0	472,203.0
Eklutna (53.3%)		23.7	23.7	23,688.7
SPP (30%)		60.1	47.6	71,910.9
		443.8	409.3	567,802.6
Plant 1		66.5	60.4	80,706
Plant 2		293.5	277.6	391,497
Eklutna		23.7	23.7	23,689
SPP		60.1	47.6	71,911

International Standards Organization (ISO)

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Generated and Purchased Power (Kilowatt Hours)
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Hank Nikkels Plant 1										
Maximum generator nameplate capacity in Kilovolt Ampere (KVA)	80,706	80,706	111,956	111,956	111,956	111,956	111,956	111,956	114,750	114,750
Net peak demand on plant (kilowatts for 60 minutes)	59,000	55,000	57,000	56,000	69,000	58,000	70,000	60,000	59,000	55,000
Plant hours connected to load	3,248	2,165	2,331	1,730	1,676	2,531	3,942	2,653	3,741	4,307
Net generation kilowatt hours (kwh)	50,849,000	45,082,278	47,782,296	33,642,939	22,223,799	54,633,112	91,338,507	55,427,594	93,723,863	73,583,819
George M. Sullivan Plant 2										
Maximum generator nameplate capacity in (KVA)	213,497	213,497	291,542	291,542	291,542	291,542	291,542	291,542	291,542	291,542
Net peak demand on plant (kilowatts for 60 minutes)	100,000	144,000	162,000	116,000	147,000	182,000	201,000	210,000	208,000	216,000
Plant hours connected to load	2,733	14,771	16,841	14,594	17,166	25,062	24,856	25,837	23,511	26,946
Net generation (kwh)	107,834,000	589,737,560	654,788,840	493,717,440	562,282,640	1,011,487,040	1,082,362,200	1,048,416,040	1,004,741,480	1,151,895,960
Plant 2A										
Maximum generator nameplate capacity in (KVA)	178,000	178,000	-	-	-	-	-	-	-	-
Net peak demand on plant (kilowatts for 60 minutes)	122,000	53,000	-	-	-	-	-	-	-	-
Plant hours connected to load	21,646	627	-	-	-	-	-	-	-	-
Net generation (kwh)	699,634,000	16,186,000	-	-	-	-	-	-	-	-
Southcentral Power Plant (the Utility's entitlement is 30%)										
Maximum generator nameplate capacity in (KVA)	239,703	239,703	239,703	239,703	239,703	-	-	-	-	-
Net peak demand on plant (kilowatts for 60 minutes)	188,000	193,000	198,000	200,570	197,000	-	-	-	-	-
Plant hours connected to load	33,290	34,674	33,042	34,118	30,476	-	-	-	-	-
Net generation (kwh)	372,998,000	373,982,000	338,331,000	392,146,000	376,802,000	-	-	-	-	-
Eklutna Hydro Project (the Utility's entitlement is 53.33%)										
Maximum generator nameplate capacity in (KVA)	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444	44,444
Net peak demand on plant (kilowatts for 60 minutes)	40,000	40,100	43,000	41,600	41,900	41,400	41,800	41,600	41,600	40,300
Plant hours connected to load	12,020	16,964	16,510	16,525	16,975	17,092	16,460	15,083	16,597	15,823
Net generation (kwh)	119,916,900	168,902,714	135,428,052	156,688,891	171,456,687	144,596,206	127,446,166	129,197,695	162,284,416	124,517,524
The utility's actual net generation received (kwh)	55,029,418	69,403,457	68,552,565	83,110,070	88,671,274	71,163,019	66,107,871	74,203,136	57,058,435	57,822,255
Off Site Generation										
Chugach Electric Assoc. (kwh)	-	-	15,501,000	-	-	-	-	300,000	330,000	-
Purchased Power										
Alaska Energy Authority (kwh)	95,933,060	90,390,272	117,013,000	127,651,000	80,928,000	116,925,000	78,661,000	79,441,000	93,863,000	80,611,000
Chugach Electric Assoc. (kwh)	-	-	1,590,000	-	-	-	-	-	-	1,733,000

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Energy Loads and Resources
Last Ten Fiscal Years

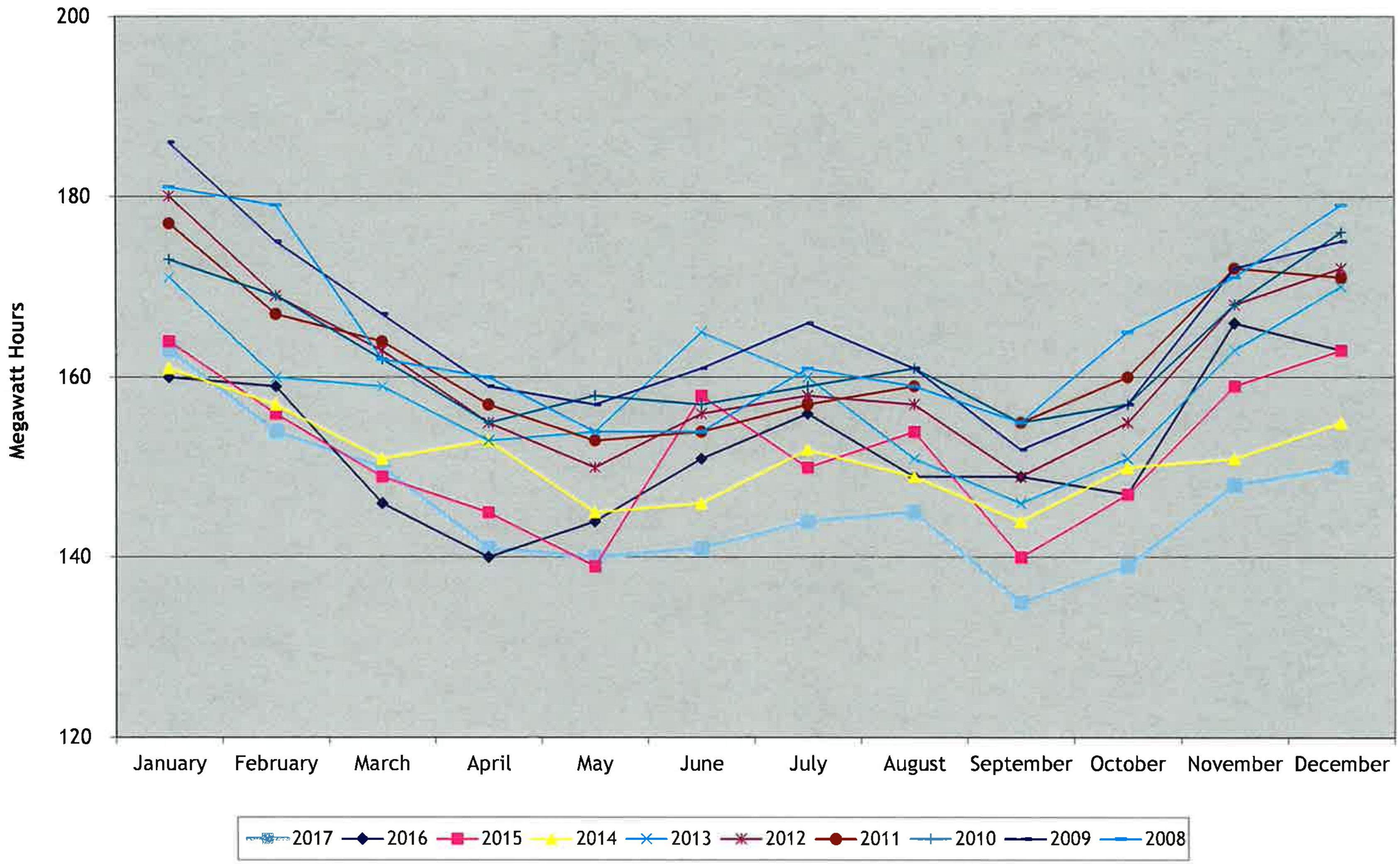
	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Sales to Customers: MWH										
Residential	127,375	127,731	130,805	133,411	139,733	146,789	143,844	143,473	147,643	147,725
Commercial	688,716	712,232	722,421	729,977	742,081	754,622	753,640	749,946	760,450	754,542
Other	149,399	151,916	151,270	149,395	165,656	199,254	214,159	215,361	207,871	216,485
Sales for Resale	387,688	213,901	257,893	94,967	56,954	157,854	185,375	121,314	107,788	214,333
Total Energy Sales	1,353,178	1,205,780	1,262,389	1,107,750	1,104,424	1,258,519	1,297,018	1,230,094	1,223,752	1,333,085
System Losses and Owner Use	59,072	50,792	50,589	38,745	46,397	36,743	43,125	49,579	45,558	55,665
Total Energy Requirements	1,412,250	1,256,572	1,312,978	1,146,495	1,150,821	1,295,262	1,340,143	1,279,673	1,269,310	1,388,750
Energy Resources:										
Own Resources	1,316,317	1,166,182	1,194,375	1,018,844	1,069,893	1,178,337	1,261,482	1,199,932	1,175,447	1,308,099
Other	95,933	90,390	118,603	127,651	80,928	116,925	78,661	79,741	93,863	80,651
Total Energy Resources	1,412,250	1,256,572	1,312,978	1,146,495	1,150,821	1,295,262	1,340,143	1,279,673	1,269,310	1,388,750

MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Monthly Peak (Megawatt Hours)
Last Ten Fiscal Years

Month	Year									
	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
January	163	160	164	161	171	180	177	173	186	181
February	154	159	156	157	160	169	167	169	175	179
March	150	146	149	151	159	163	164	162	167	162
April	141	140	145	153	153	155	157	155	159	160
May	140	144	139	145	154	150	153	158	157	154
June	141	151	158	146	165	156	154	157	161	154
July	144	156	150	152	160	158	157	159	166	161
August	145	149	154	149	151	157	159	161	161	159
September	135	149	140	144	146	149	155	155	152	155
October	139	147	147	150	151	155	160	157	157	165
November	148	166	159	151	163	168	172	168	172	171
December	150	163	163	155	170	172	171	176	175	179

MUNICIPALITY OF ANCHORAGE
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)

Monthly Peak (Megawatt Hours)



MUNICIPALITY OF ANCHORAGE, ALASKA
ELECTRIC UTILITY FUND
Statistical Section (Unaudited)
Miscellaneous Statistical Information
Last Ten Fiscal Years

	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Number of customers	31,074	31,081	30,932	30,751	30,767	30,747	30,603	30,481	30,406	30,352
Number of street lights	3,879	3,891	3,897	3,901	3,911	3,924	3,930	3,948	4,027	4,132
Circuit miles of overhead distribution line	118	118	120	122	123	124	125	130	131	136
Miles of underground distribution line	253	253	253	254	248	250	252	257	254	243
Plant generation capacity (30 degrees fahrenheit) - KW	424,560	444,260	395,470	395,470	395,470	364,500	364,500	364,500	366,100	366,100

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Independent Auditor's Report on Internal Control Over Financial Reporting and on Compliance and Other Matters Based on an Audit of Financial Statements Performed in Accordance With *Government Auditing Standards*

Honorable Mayor and Members of the Assembly
Municipality of Anchorage, Alaska

We have audited, in accordance with the auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States, the financial statements of the Electric Utility Fund, an enterprise fund of the Municipality of Anchorage, Alaska, which comprise the statement of financial position as of December 31, 2017, and the related statements of activities and cash flows for the year then ended, and the related notes to the financial statements, and have issued our report thereon dated December 18, 2018.

Internal Control Over Financial Reporting

In planning and performing our audit of the financial statements, we considered the Electric Utility Fund's internal control over financial reporting (internal control) to determinate the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Electric Utility Fund's internal control. Accordingly, we do not express an opinion on the effectiveness of the Electric Utility Fund's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct, misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis. A *significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies and therefore, material weaknesses or significant deficiencies may exist that have not been identified. We did identify a certain deficiency in internal control, described in the accompanying schedule of findings and responses as item 2017-001 that we consider to be a material weakness.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Electric Utility Fund's financial statements are free from material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

The Electric Utility Fund's Response to Findings

The Electric Utility Fund's response to the findings identified in our audit is described in the accompanying schedule of findings and responses. The Electric Utility Fund's response was not subjected to the auditing procedures applied in the audit of the financial statements and, accordingly, we express no opinion on it.

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal control and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the entity's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the entity's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

BDO USA, LLP

Anchorage, Alaska
December 18, 2018

Municipality of Anchorage, Alaska
Electric Utility Fund

Schedule of Findings and Responses
Year Ended December 31, 2017

Section I - Summary of Auditor's Results

Financial Statements

Type of auditor's report issued:	Unmodified	
Internal control over financial reporting:		
Material weakness(es) identified?	X yes	___ no
Significant deficiency(ies) identified?	___ yes	X (none reported)
Noncompliance material to financial statements noted?	___ yes	X no

Section II - Financial Statement Findings Required to be Reported in Accordance with *Government Auditing Standards*

<u>Finding 2017-001</u> **SAP Software Conversion - Internal Control over Financial Reporting - Material Weakness**

Criteria: A properly functioning ERP accounting system is an integral component in providing accurate accounting data and information. Without a functioning ERP accounting system, it is difficult for management to have access to financial information that is reliable and properly reported, which is necessary for management to prevent or detect and correct misstatements on a timely basis.

Condition: The Electric Utility Fund did not have in place a properly functioning ERP accounting system. The Electric Utility Fund placed the SAP system into service on September 11, 2017 (payroll only) and October 1, 2017 (remainder of the system). Immediately, Management became aware of significant errors in transaction processing and financial reporting due to defects in the system. A significant number of the defects were not corrected as of year-end.

Cause: The implementation of the SAP system was managed at the Municipality level, where management did not fully assess the functionality of the SAP system prior to bringing the system online in 2017. Management neglected to conduct proper testing prior to implementation.

Effect: Management was unable to properly reconcile and close the 2017 financial records in a timely manner. A significant number of account balances and financial statement areas were not fully adjusted, reconciled and closed until months after year-end.

Recommendation: We encourage management work with representatives at the Municipality who are responsible for the project management of SAP to continue addressing the remaining defects and make the necessary modifications to ensure the system is operating correctly.

Views of responsible officials: Management concurs with the finding. See corrective action plan.

MUNICIPAL
LIGHT & POWER

Corrective Action Plan
Year ended December 31, 2017

Name of contact person responsible for corrective action:	Mollie Morrison Chief Financial Officer, Municipal Light & Power 907-263-5205

Financial Statement Finding 2017-001
SAP Software Conversion - Internal Control over Financial Reporting - Material Weakness

Corrective Action Plan	Utility management will work with representatives at the Municipality of Anchorage who are responsible for the project management of SAP to continue addressing the remaining defects and make the necessary modifications to ensure the system is operating correctly.
Expected Completion Date	December 31, 2019

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MUNICIPAL LIGHT & POWER
Monthly Business Report
September 30, 2020
as of 10/12/20

These financial statements are unaudited and prepared for internal use only. Please use them in conjunction with ML&P's annual audited financial statements. Financial information presented in these statements is for management analysis and may differ from the audited financial statements in some instances.

Municipal Light & Power
Business Report

STATEMENT	PAGE
Statement of Net Position (condensed)	2
Statement of Revenues, Expenses, and Changes in Net Position, Year to Date	3
Statement of Cash Flows	4
Notes to Business Report	5

MUNICIPAL LIGHT AND POWER
Statements of Net Position
As of September 30, 2020 and December 31, 2019

	September 30, 2020	Dec. 31, 2019
ASSETS AND DEFERRED OUTFLOWS OF RESOURCES		
PLANT IN SERVICE		
Plant In Service	$ 1,366,862,143	$ 1,359,235,730
Less Accumulated Depreciation and Amortization	(533,846,532)	(514,270,008)
Net Plant In Service	833,015,611	844,965,722
Intangible Plant, net	2,320,949	2,399,903
Construction Work In Progress	31,962,785	29,967,785
Total Plant	867,299,345	877,333,410
RESTRICTED ASSETS		
Current:		
Debt Service Account	12,262,326	2,056,512
Restricted Equity In General Cash Pool	1,330,421	1,260,642
Other Special Investments and Cash	58,201,244	31,802,868
Non-Current:		
Revenue Bond Reserve Investment	24,543,769	24,387,434
Asset Retirement Obligation Sinking Fund	17,361,418	16,342,806
Total Restricted Assets	113,699,178	75,850,262
CURRENT ASSETS		
Equity In General Cash Pool	33,958,859	67,475,637
Net Accounts Receivable	13,051,350	15,421,983
Inventory Of Material & Supplies	29,120,977	32,134,009
Other Current Assets	790,710	534,954
Total Current Assets	76,921,896	115,566,583
OTHER ASSETS	8,955,020	7,752,216
Total Assets	1,066,875,439	1,076,502,471
DEFERRED OUTFLOWS OF RESOURCES	1,526,876	1,550,632
TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	$ 1,068,402,315	$ 1,078,053,103
LIABILITIES, DEFERRED INFLOWS OF RESOURCES AND NET POSITION		
CURRENT LIABILITIES		
Accounts Payable	$ 7,916,019	$ 13,316,706
Compensated Absences Payable	3,023,208	2,387,262
Accrued Payroll Liabilities	210,710	1,816,951
Accrued Interest Payable	5,603,344	1,722,475
Long-Term Obligation Maturing Within One Year	8,075,000	8,075,000
Customer Deposits	1,330,421	1,260,642
Total Current Liabilities	26,158,702	28,579,036
LONG-TERM DEBT		
Revenue Bonds Payable	299,700,000	299,700,000
Net Unamortized Premium (Discount)	14,987,842	15,831,235
Total Long-Term Debt	314,687,842	315,531,235
OTHER NONCURRENT LIABILITIES		
Notes Payable	191,900,000	191,900,000
Asset Retirement Obligation	25,130,178	24,332,547
Net Pension Liability	10,094,592	10,094,592
Net OPEB Liability	252,675	252,675
Other Noncurrent Liabilities	4,194,450	6,225,482
Total Other Noncurrent Liabilities	231,571,895	232,805,296
Total Liabilities	572,418,439	576,915,567
DEFERRED INFLOWS OF RESOURCES	189,002,420	201,815,619
NET POSITION		
Net Investment in Capital Assets	209,152,928	214,935,301
Restricted for Debt Service	6,649,205	326,473
Restricted for Operations	14,391,000	14,391,000
Unrestricted	76,788,323	69,669,143
Total Net Position	306,981,456	299,321,917
TOTAL LIABILITIES, DEFERRED INFLOWS OF RESOURCES AND NET POSITION	$ 1,068,402,315	$ 1,078,053,103

MUNICIPAL LIGHT AND POWER
Statement of Revenues, Expenses, and Changes in Net Position
For the Nine Months Ending
September 30, 2020 and September 30, 2019

	2020	2019	Variance
OPERATING REVENUES			
Residential Sales	$ 19,546,575	$ 20,272,832	$ (726,257)
Commercial and Industrial Sales	72,703,601	85,919,196	(13,215,595)
Military Sales	11,345,820	13,593,490	(2,247,670)
Sales for Resale	1,800,115	8,686,687	(6,886,572)
Other Operating Revenue	2,899,653	(3,817,527)	6,717,180
Total Operating Revenue	108,295,764	124,654,678	(16,358,914)
OPERATING EXPENSES			
Production	40,456,463	54,497,768	(14,041,305)
Transmission	1,400,701	757,268	643,433
Distribution	11,600,182	10,298,608	1,301,574
Customer Service	2,691,328	2,750,987	(59,659)
Administrative and General	7,949,073	7,927,864	21,209
Depreciation and Depletion, net	21,313,788	21,901,482	(587,694)
Taxes Other Than Income	486,312	533,079	(46,767)
Regulatory Debits/Credits	(513,303)	(1,159,961)	646,658
Total Operating Expenses	85,384,544	97,507,095	(12,122,551)
Net Operating Income	22,911,220	27,147,583	(4,236,363)
NON-OPERATING REVENUES			
Interest Income	4,042,194	6,085,201	(2,043,007)
BABs Subsidy	1,837,166	1,831,308	5,858
Other Revenues	14,218	-	14,218
Total Non-Operating Revenues	5,893,578	7,916,509	(2,022,931)
NON-OPERATING EXPENSES			
Interest Expense on Long-Term Obligations	12,090,997	12,376,115	(285,118)
Other Interest Expense	1,629,739	3,847,613	(2,217,874)
Allowance for Funds Used During Construction	(752,701)	(395,689)	(357,012)
Amortization of Deferred Charges	23,756	27,351	(3,595)
Loss on Disposal of Property	458,782	36,646	422,136
Other Expenses	50,000	49,246	754
Total Non-Operating Expenses	13,500,573	15,941,282	(2,440,709)
Net Non-Operating Income	(7,606,995)	(8,024,773)	417,778
Income Before Transfers	15,304,225	19,122,810	(3,818,585)
TRANSFERS TO OTHER FUNDS			
Municipal Utility Service Assessment	(7,454,377)	(7,234,454)	(219,923)
Transfer to /from Other Funds	(190,311)	-	(190,311)
Total Transfers	(7,644,688)	(7,234,454)	(410,234)
Change in Net Position	7,659,537	11,888,356	(4,228,819)
Net Position - Beginning of Year	299,321,913	$ 285,239,721	$ 14,082,192
Ending Net Position	$ 306,981,450	$ 297,128,077	$ 14,082,192

MUNICIPAL LIGHT AND POWER
Statement of Cash Flows
As of September 30, 2020 and December 31, 2019

	September 30, 2020	Dec. 31, 2019
CASH FLOWS FROM OPERATING ACTIVITIES		
Operating Income	$ 22,911,220	$ 35,160,030
Adjustments to Reconcile Operating Income to Net Cash Provided (Used) by Operating Activities:		
Depreciation and Amortization	21,313,788	29,176,277
PERS and OPEB on Behalf	-	(158,592)
Allowance for Uncollectible Accounts	(297,234)	197,845
Other Income (Expenses)	(35,782)	(49,246)
Changes in Assets, Liabilities and Deferred Inflows of Resources Which Increase (Decrease) Cash:		
Accounts Receivable	2,667,867	(145,301)
Unbilled Reimbursable Work Orders	(106,270)	264,112
Inventories	3,013,031	(745,878)
Customer Deposits	69,779	35,189
Deferred Charges and Other Assets	1,207,932	1,017,507
Other Noncurrent Liabilities	(948,185)	4,983,163
Accounts Payable	(5,400,688)	1,281,592
Deferred Inflows of Resources	(9,601,625)	2,133,053
Compensated Absences Payable	635,946	(139,161)
Accrued Payroll Liabilities	(1,606,241)	310,139
Total Adjustments	10,912,318	38,160,699
Net Cash Provided by Operating Activities	33,823,538	73,320,729
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES		
Transfer From/To Other Funds	(190,311)	-
Municipal Utility Service Assessment	(9,939,169)	(9,645,938)
Net Cash Provided (Used) by Noncapital Financing Activities	(10,129,480)	(9,645,938)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Proceeds from Issuance of Short-Term Obligations	-	-
Principal Payments on Short-Term Obligations	-	-
Interest Payments on Short-Term Obligations	(1,899,654)	(4,982,733)
Proceeds from Issuance of Long-Term Obligations	-	-
Bond Sale Costs	-	-
Principal Payments on Long-Term Obligations	-	(7,730,000)
Interest Payments on Long-Term Obligations	(8,301,574)	(16,950,747)
Interest Payments on Long-Term Obligations to Associated Company	(271,982)	(607,592)
Interest Subsidy on Build America Bonds	1,224,777	2,445,649
Acquisition and Construction of Capital Assets	(17,203,818)	(33,920,580)
Contributed Capital	2,585,235	2,298,023
Proceeds From the Sale of Property	-	-
Net Cash Provided (Used) by Capital & Related Financing Activities	(23,867,016)	(59,447,980)
CASH FLOWS FROM INVESTING ACTIVITIES		
Investment Income Received	4,505,097	7,303,712
Net (Deposits to)/Withdrawals from Restricted Funds	(37,779,138)	(5,926,061)
Net Cash Provided by Investing Activities	(33,274,041)	1,377,651
Net Increase (Decrease) In Cash	(33,446,999)	5,604,462
Cash, Beginning of Year	68,736,279	63,131,817
Cash at the End of Reporting Period	$ 35,289,280	$ 68,736,279
CASH AND CASH EQUIVALENTS		
Restricted:		
Restricted Equity in General Cash Pool	$ 1,330,421	$ 1,260,642
Interim Revenue Escrow Invest	-	-
Total Restricted Cash	1,330,421	1,260,642
Unrestricted -		
Equity in General Cash Pool	33,958,859	67,475,637
Total Cash and Cash Equivalents, End of Period	$ 35,289,280	$ 68,736,279
NON-CASH INVESTING, CAPITAL AND FINANCING ACTIVITIES		
Contributed Capital From Deferred Inflows of Resources	$ 15,498	$ 794,741
Portion of Plant From AFUDC	752,701	595,493
Total Non-Cash Investing, Capital and Financing Activities	$ 768,199	$ 1,390,234

Municipal Light and Power
Notes to Business Report
September 30, 2020

1 These statements and schedules are prepared for the purposes of analysis and governance by management at Municipal Light & Power and the Municipality of Anchorage, the ML&P Advisory Commission and the Anchorage Municipal Assembly and are not intended to be used by any other parties. These statements and schedules are not audited and no claims are made by management that they are the equivalents of audited financial statements for the periods presented.

2 Other GAAP disclosures reported in the Electric Utility's 2019 audited financial statements

Other GAAP Disclosures

The Municipality of Anchorage has entered into an agreement to sell certain assets and discharge certain liabilities of Municipal Light & Power (the Utility) to Chugach Electric Association (CEA). CEA is a non-governmental entity and, as such, follows the Financial Accounting Standards Board (FASB) accounting framework to prepare its financial statements. The Utility's financial statements are prepared according to the GASB framework, and therefore the accounting for certain items could differ from the accounting treatment by CEA. The table beginning below presents relevant authoritative accounting pronouncements under the respective GASB and FASB frameworks to provide clarification to the users of the Utility's audited financial statements.

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Net Pension Liabilities	GASBS 68 Paragraph 59 - A liability should be recognized for the employer's proportionate share of the collective net pension liability, measured as of a date (measurement date) no earlier than the end of the employer's prior fiscal year, consistently applied from period to period. The employer's proportionate share of the collective net pension liability should be measured by: a. Determining the employer's proportion—a measure of the proportionate relationship of (1) the employer (and, to the extent associated with the employer, nonemployer contributing entities, if any, that provide support for the employer but that are not in a special funding situation) to (2) all employers and all nonemployer contributing entities. b. Multiplying the collective net pension liability by the employer's proportion calculated in (a).	FASB ASC Topic 715-30-25 Paragraph 1 - If the projected benefit obligation exceeds the fair value of plan assets, the employer shall recognize in its statement of financial position a liability that equals the unfunded projected benefit obligation. If the fair value of plan assets exceeds the projected benefit obligation, the employer shall recognize in its statement of financial position an asset that equals the overfunded projected benefit obligation.

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to Pensions	GASBS 68 Paragraph 71 - Changes in the collective net pension liability should be included in collective pension expense in the current measurement period except as indicated below: a. Each of the following should be included in collective pension expense, beginning in the current measurement period, using a systematic and rational method over a closed period equal to the average of the expected remaining service lives of all employees that are provided with pensions through the pension plan (active employees and inactive employees) determined as of the beginning of the measurement period: (1) Differences between expected and actual experience with regard to economic and demographic factors (differences between expected and actual experience) in the measurement of the total pension liability (2) Changes of assumptions about future economic or demographic factors or of other inputs (changes of assumptions or other inputs). The portion of (1) and (2) not included in collective pension expense should be included in collective deferred outflows of resources or deferred inflows of resources related to pensions. b. The difference between projected and actual earnings on pension plan investments should be included in collective pension expense using a systematic and rational method over a closed five-year period,	ASC Topic 715-30-35 Paragraph 18 - As established in the definition of the term, a gain or loss results from a change in the value of either the projected benefit obligation or the plan assets resulting from experience different from that assumed or from a change in an actuarial assumption. Paragraph 19 - Because gains and losses may reflect refinements in estimates as well as real changes in economic values and because some gains in one period may be offset by losses in another or vice versa, this Subtopic does not require recognition of gains and losses as components of net pension cost of the period in which they arise. Paragraph 22 - Asset gains and losses are differences between the actual return on plan assets during a period and the expected return on plan assets for that period. Asset gains and losses include both changes reflected in the market-related value of plan assets and changes not yet reflected in the market-related value (that is, the difference between the fair value of assets and the market-related value). Gains or losses on transferable securities issued by the employer and included in plan assets are also included in asset gains and losses. Paragraph 23 - In other words, the expected return on plan assets generally will be different from the actual return on plan assets for the year. This Subtopic provides for recognition of that difference (a net gain or loss) in other comprehensive income in the period it arises. The amount recognized in other

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to Pensions, continued	beginning in the current measurement period. The amount not included in collective pension expense should be included in collective deferred outflows of resources or deferred inflows of resources related to pensions. Collective deferred outflows of resources and deferred inflows of resources arising from differences between projected and actual pension plan investment earnings in different measurement periods should be aggregated and included as a net collective deferred outflow of resources related to pensions or a net collective deferred inflow of resources related to pensions.	comprehensive income is also a component of net periodic pension cost for the current period. Thus, the amount recognized in other comprehensive income and the actual return on plan assets, when aggregated, equal the expected return on plan assets. The amount recognized in accumulated other comprehensive income affects future net periodic pension cost through subsequent amortization, if any, of the net gain or loss.
Net Other Post Employment Benefits Liabilities	GASBS 75 Paragraph 109 - A liability should be recognized for the employer's proportionate share of the collective net OPEB liability determined in conformity with paragraphs 59-61. (Paragraph 59 - The employer's proportionate share of the collective net OPEB liability should be measured by: (a) Determining the employer's proportion – a measure of the proportionate relationship of (1) the employer.. to (2) all employers and all nonemployer contributing entities… (b) Multiplying the collective net OPEB liability (determined in conformity with paragraphs 70-85) by employer's proportion calculated in (a). Paragraph 70 – The collective net OPEB liability should be measured as the total OPEB liability net of the	FASB ASC Topic 715-60-25 Paragraph 1 - An employer that sponsors one or more single-employer defined benefit postretirement plans other than pensions shall recognize in its statement of financial position the funded statuses of those plans. The employer shall aggregate the statuses of all overfunded plans and recognize that amount as an asset in its statement of financial position. It also shall aggregate the statuses of all underfunded plans and recognize that amount as a liability in its statement of financial position. Paragraph 2 - As indicated in paragraphs 715-60-35-125 through 35-126 remeasurement of both plan assets and the accumulated postretirement benefit obligation may be necessary. Upon remeasurement, a business entity shall adjust its statement of financial position in a

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Net Other Post Employment Benefits Liabilities, continued	OPEB plan’s fiduciary net position. Paragraph 71 - The total OPEB liability should be determined by (a) an actuarial valuation as of the measurement date or (b) the use of update procedures to roll forward to the measurement date amounts from an actuarial valuation as of a date no more than 30 months and 1 day earlier than the employer’s most recent fiscal year end.. If update procedures are used and significant changes occur between the actuarial valuation date and the measurement date, professional judgment should be used to determine the extent of procedures needed to roll forward the measurement from the actuarial valuation to the measurement date, and consideration should be given to whether a new actuarial valuation is needed. For purposes of this determination, the effects of changes in the discount rate resulting from changes in the OPEB plan’s fiduciary net position or from changes in the municipal bond rate, if applicable, should be among the factors evaluated. For accounting and financial reporting purposes, an actuarial valuation of the total OPEB liability should be performed at least biennially. More frequent actuarial valuations are encouraged.	subsequent interim period to reflect the overfunded or underfunded status of the plan consistent with that measurement date.

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to OPEB	GASBS 75 Paragraph 86 - Changes in the collective net OPEB liability should be included in collective OPEB expense in the current measurement period except as indicated below: (a) If the alternative measurement method is not used to measure the total OPEB liability, each of the following should be recognized in collective OPEB expense, beginning in the current measurement period, using a systematic and rational method over a closed period equal to the average of the expected remaining service lives of all employees that are provided with OPEB through the OPEB plan determined as of the beginning of the measurement period: (1) Differences between expected and actual experience with regard to economic or demographic factors (differences between expected and actual experience) in the measurement of the total OPEB liability. (2) Changes of assumptions about future economic or demographic factors or of other inputs (changes of assumptions or other inputs). The portion of (1) and (2) not recognized in collective OPEB expense should be reported as collective deferred outflows of resources or deferred inflows of resources related to OPEB. (b) The difference between projected and actual earnings on OPEB plan investments should be included in collective OPEB expense using a	ASC Topic 715-60-35 Paragraph 7 - As with other forms of deferred compensation, the cost of providing postretirement benefits shall be attributed to the periods of employee service rendered in exchange for those future benefits pursuant to the terms of the plan. That cost notionally represents the change in the unfunded accumulated postretirement benefit obligation for the period, ignoring employer contributions to the plan, plan settlements, and payments made by the employer directly to retirees. However, changes in that unfunded obligation that arise from experience gains and losses and the effects of changes in assumptions may be recognized as a component of net periodic postretirement benefit cost on a delayed basis. Paragraph 8 - Thus any change in the accumulated postretirement benefit obligation or the plan assets (other than contributions and benefit payments) either is initially recognized in other comprehensive income or is included in net periodic postretirement benefit cost. Paragraph 24 - Because gains and losses may reflect refinements in estimates as well as real changes in economic values and because some gains in one period may be offset by losses in another or vice versa, this Subtopic does not require recognition of gains and losses as components of net postretirement benefit cost of the period in which they arise.

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Deferred Inflows of Resources and Deferred Outflows of Resources Related to OPEB, continued	systematic and rational method over a closed five-year period, beginning in the current measurement period. The amount not included in collective OPEB expense should be included in collective deferred outflows of resources or deferred inflows of resources related to OPEB. Collective deferred outflows of resources and deferred inflows of resources arising from differences between projected and actual OPEB plan investment earnings in different measurement periods should be aggregated and included as a net collective deferred outflow of resources related to OPEB or a net collective deferred inflow of resources related to OPEB. (c) Contributions to the OPEB plan from employers or nonemployer contributing entities should not be included in collective OPEB expenses.	Paragraph 25 - Gains and losses that are not recognized immediately as a component of net periodic postretirement benefit cost shall be recognized as increases or decreases in other comprehensive income as they arise. Paragraph 27 - Plan asset gains and losses are differences between the actual return on plan assets during a period and the expected return on plan assets for that period. Asset gains and losses include both of the following: a. Changes reflected in the market-related value of plan assets b. Changes not yet reflected in the market-related value of plan assets (that is, the difference between the fair value and the market-related value of plan assets).

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Contributions in Aid of Construction	GASBCS4 Paragraph 34. A deferred inflow of resources is an acquisition of net position by the government that is applicable to a future reporting period.	FASB ASC 210-10-S99 Paragraph 13(b) Tangible and intangible utility plant of a public utility company shall be segregated so as to show separately the original cost, plant acquisition adjustments, and plant adjustments, as required by the system of accounts prescribed by the applicable regulatory authorities.
Restricted Assets	GASBS 34 Paragraph 99 - Restricted assets should be reported when restrictions on asset use change the nature or normal understanding of the availability of the asset. For example, cash and investments normally are classified as current assets, and a normal understanding of these assets presumes that restrictions do not limit the government's ability to use the resources to pay current liabilities. But cash and investments held in a separate account that can be used to pay debt principal and interest only (as required by the debt covenant) and that cannot be used to pay other current liabilities should be reported as restricted assets. Because restricted assets may include temporarily invested debt proceeds or other resources that are not generated through operations (such as customer deposits), the amount reported as restricted assets will not necessarily equal restricted net position.	FASB ASC 210-10-S99-1 Paragraph 1 - Cash and cash items. Separate disclosure shall be made of the cash and cash items which are restricted as to withdrawal or usage. The provisions of any restrictions shall be described in a note to the financial statements. Restrictions may include legally restricted deposits held as compensating balances against short-term borrowing arrangements, contracts entered into with others, or company statements of intention with regard to particular deposits.

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Transfers to Other Funds	GASBS 34 Paragraph 112b - Nonreciprocal interfund activity is the internal counterpart to nonexchange transactions. It includes: Interfund transfers—flows of assets (such as cash or goods) without equivalent flows of assets in return and without a requirement for repayment. This category includes payments in lieu of taxes that are not payments for, and are not reasonably equivalent in value to, services provided.	Not addressed in FASB reporting framework
Non-Operating Revenues and Expenses	GASBS 34 Paragraph 102 - Governments should establish a policy that defines operating revenues and expenses that is appropriate to the nature of the activity being reported, disclose it in the summary of significant accounting policies, and use it consistently from period to period. A consideration for defining a proprietary fund's operating revenues and expenses is how individual transactions would be categorized for purposes of preparing a statement of cash flows. Transactions for which cash flows are reported as capital and related financing activities, noncapital financing activities, or investing activities normally would not be reported as components of operating income.	FASB ASC Topic 360-10-45-5 - A gain or loss recognized on the sale of a long-lived asset that is not a discontinued operation shall be included in income from continuing operations before income taxes.

Reported in the Utility's Financial Statements	GASB Authoritative Guidance	FASB Authoritative Guidance
Asset Retirement Obligations	The Utility uses the Guidance from FASB ASC Topic 980 (Formerly FASBS 143) to record asset retirement obligations. The implementation date for GASBS 83 *Certain Asset Retirement Obligations* has been postponed until fiscal year 2020.	FASB ASC Topic 980-410-25-2 - Many rate-regulated entities currently provide for costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of subtopic 410-20; others result from costs that are not within the scope of the subtopic. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs for financial reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. If the requirements of this topic are met, a regulated entity shall also recognize a regulatory asset or liability for differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting pursuant to that Subtopic and rate-making purposes.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited pro forma condensed consolidated financial statements give effect to the Business Combination of Chugach Electric Association, Inc. ("Chugach") and Municipal Light & Power ("ML&P"). The historical financial information has been adjusted in these unaudited pro forma condensed consolidated financial statements to give effect to pro forma events that are (1) directly attributable to the Business Combination and the related financing transaction, (2) factually supportable, and (3) with respect to the statements of operations, expected to have a continuing impact on the post-combination company.

Unaudited Pro Forma
Condensed Consolidated Balance Sheet
As of September 30, 2020

	Chugach Electric Association, Inc.	Municipal Light & Power	Pro Forma Adjustments	Combined Pro Forma	Note Ref.
ASSETS					
Net utility plant	$ 702,193,797	$ 867,299,345	$ (169,199,321)	$ 1,429,189,677	3b
			33,985,330		3f
			(5,089,474)		4a
Other property and investments	11,778,526	113,699,178	(1,330,421)	63,950,188	3c
			(51,197,095)		4b
			(9,000,000)		4j
Current assets					
Cash and cash equivalents	3,438,865	33,958,859	1,330,421	46,678,426	3c
			(33,958,859)		4c
			41,909,140		4d
Restricted cash and cash equivalents	500,376	0	0	500,376	
Accounts receivable, net	26,087,945	13,051,350	0	39,139,295	
Inventory	35,797,938	29,120,977	0	64,918,915	
Prepayments and other assets	4,759,348	3,912,311	0	8,671,659	
Total current assets	70,584,472	80,043,497	9,280,702	159,908,671	
Other long-term assets	56,325,132	7,360,295	(645,196)	98,647,183	3a
			(2,043,048)		3e
			(4,750,000)		4l
			42,400,000		4l
TOTAL ASSETS	$ 840,881,927	$ 1,068,402,315	$ (157,588,523)	$ 1,751,695,719	

(Continued)

Unaudited Pro Forma
Condensed Consolidated Balance Sheet (continued)
As of September 30, 2020

	Chugach Electric Association Inc.	Municipal Light & Power	Pro Forma Adjustments	Combined Pro Forma	Note Ref.
LIABILITIES, EQUITIES AND MARGINS					
Equities and margins					
Memberships	$ 1,797,622	$ 0	$ 0	$ 1,797,622	
Patronage capital	179,804,924	0	(3,709,107)	176,095,817	4k
Other	15,372,809	0	0	15,372,809	
Total equities and margins	196,975,355	0	(3,709,107)	193,266,248	
Current liabilities					
Current portion of long-term obligations	24,175,424	8,075,000	(8,075,000)	42,175,424	4e
			18,000,000		4f
Accounts payable and accrued expenses	27,743,359	16,753,281	(213,194)	44,283,446	4g
Other current liabilities	68,309,885	1,330,421	0	69,640,306	
Total current liabilities	120,228,668	26,158,702	9,711,806	156,099,176	
Non-current liabilities					
Long-term obligations, excluding current portion	429,683,330	299,700,000	(299,700,000)	1,202,683,330	4e
			773,000,000		4f
Unamortized debt issuance costs	(2,638,644)	14,987,842	(2,043,048)	(6,167,052)	3e
			(12,944,794)		4e
			(3,528,408)		4m
Notes payable	27,816,000	191,900,000	(191,900,000)	27,816,000	4e
Operating & financing lease liabilities	605,371	0	0	605,371	4h
Deferred credits	875,250	0	45,870,840	46,746,090	3g, 4j
Cost of removal obligation	65,078,892	25,130,178	33,985,330	124,194,400	3f
Other non-current liabilities	2,257,705	14,541,717	(10,347,267)	6,452,155	3a, 4i
Total non-current liabilities	523,677,904	546,259,737	332,392,653	1,402,330,294	
Deferred inflows of resources	0	189,002,420	(932,259)	0	3a
			(169,199,321)		3b
			(18,870,870)		3g
Total net position	0	306,981,456	(306,981,456)	0	4h
TOTAL LIABILITIES, EQUITIES AND MARGINS	$ 840,881,927	$ 1,068,402,315	$ (157,588,523)	$ 1,751,695,719	

See accompanying notes to pro forma financial statements.

Unaudited Pro Forma
Condensed Consolidated Statements of Operations
For the Nine Months Ended September 30, 2020

	Chugach Electric Association, Inc.	Municipal Light & Power	Pro Forma Adjustments	Combined Pro Forma	Note Ref.
Operating revenue	$ 156,951,285	$ 108,295,764	$ 0	$ 265,247,049	
Operating expenses					
Production	72,732,180	40,456,463	1,884,350	115,072,993	4r
Transmission	5,153,979	1,400,701	0	6,554,680	
Distribution	12,254,227	11,600,182	0	23,854,409	
Customer service and sales	5,391,441	2,691,328	0	8,082,769	
Administrative, general and other	18,245,094	8,435,385	7,644,688	38,299,926	3d
			458,782		3e
			4,750,000		4s
			(1,234,023)		4p
Depreciation and amortization	23,969,958	20,800,485	(173,522)	44,770,443	4q
Total operating expenses	$ 137,746,879	$ 85,384,544	$ 13,330,275	$ 236,461,698	
Interest expense, net	16,309,073	13,720,736	(1,813,410)	34,358,238	3e
			(10,253,831)		4n
			16,395,670		4o
Net operating margins	$ 2,895,333	$ 9,190,484	$ (17,658,704)	$ (5,572,887)	
Nonoperating margins	324,189	(1,530,947)	7,644,,688	5,083,302	3d
			458,782		3e
			(1,813,410)		3e
Assignable margins	$ 3,219,522	$ 7,659,537	$ (11,368,644)	$ (489,585)	

See accompanying notes to pro forma financial statements.

Notes to Unaudited Condensed Consolidated Pro Forma Financial Statements

1. PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited pro forma financial statements include the accounts of Chugach Electric Association, Inc. ("Chugach") and have been prepared in accordance with generally accepted accounting principles for pro forma financial information. Accordingly, they do not include all of the information and footnotes required by United States of America generally accepted accounting principles ("GAAP") for complete financial statements. They should be read in conjunction with Chugach's audited financial statements for the year ended December 31, 2019, filed as part of Chugach's annual report on Form 10-K. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. The results of operations for interim periods are not necessarily indicative of the results that may be expected for an entire year or any other period.

2. ML&P ACQUISITION

In December 2017, the Mayor of Anchorage, Alaska, announced plans to place a proposition on the April 3, 2018 municipal ballot allowing the voters to authorize the sale of Municipal Light & Power ("ML&P") to Chugach. The proposition was approved by Anchorage voters 65.08% to 34.92% per the certified election results. Chugach and the Municipality of Anchorage, Alaska ("MOA") negotiated final sales agreements and associated documents. The sale of ML&P was approved by the Anchorage Assembly on December 4, 2018 and the Chugach Board of Directors gave its final approval on December 19, 2018.

On December 28, 2018, Chugach entered into the Asset Purchase and Sale Agreement ("APA") with the MOA to acquire substantially all of the assets, and certain specified liabilities of ML&P, subject to approval by the RCA. On December 28, 2018, Chugach also entered into an Eklutna Power Purchase Agreement ("PPA Agreement"), a Payment in Lieu of Taxes Agreement ("PILT Agreement"), and a BRU Fuel Agreement ("Ancillary Agreements") with the MOA.

During the first week of April 2019, pursuant to the APA, Chugach and the MOA jointly submitted applications to amend their respective Certificates of Public Convenience and Necessity("CPCN") to permit Chugach to provide electric service in ML&P's legacy service territory. The Regulatory Commission of Alaska ("RCA") accepted the filing as complete on April 18, 2019, and a procedural conference was held on April 22, 2019. On May 8, 2019, the RCA issued an order indicating that a final order in the case was expected by November 19, 2019. In addition, the RCA granted the petitions to intervene filed by Matanuska Electric Association, Inc. ("MEA"); Providence Health and Services ("Providence"); Golden Valley Electric Association, Inc. ("GVEA"); the Federal Executive Agencies ("FEA"); and Homer Electric Association, Inc. ("HEA") / Alaska Electric and Energy Cooperative, Inc. Hearings on the acquisition were held in August and September 2019. On October 1, 2019, all parties agreed to an extension for the RCA final order in the case to February 17, 2020. The statutory timeline for issuance of a final order and to rule on the Stipulations was extended to February 28, 2020. On February 27, 2020, the RCA issued an order extending the statutory timeline and extended the time to consider the Stipulation to May 28, 2020. The RCA issued an order on May 28, 2020, accepting the Stipulations and approved the acquisition of ML&P subject to certain conditions. The conditions included required filings within 90 days of the Order date for: 1) unified fuel and purchased power rates, and 2) the gas transfer price for natural gas from the Beluga River Unit ("BRU"). Additionally, the RCA required Chugach to form a tight Power Pooling Agreement with MEA.

In June 2019, Chugach and GVEA entered into a Memorandum of Understanding ("MOU") in which Chugach agreed to provide GVEA non-firm energy, wheeling and ancillary services for a 3-year period under terms and conditions consistent with its operating tariff, and will make available 5 MW of Bradley Lake capacity to GVEA for a 5-year period. Excluding fuel, the MOU is expected to provide over $10 million of additional revenue to the Chugach system over the term of the agreement. GVEA withdrew its petition to intervene regarding the ML&P acquisition.

Pursuant to the original APA, upon closing, Chugach transferred the purchase price of $767.8 million less the estimated accrued leave liability and the estimated net book value of designated excluded assets. The APA also includes terms for post-closing purchase price adjustments. In September 2019, Chugach entered into APA Amendment No. 1, which provided that the purchase price shall reflect net book value of ML&P assets at closing and amended related definitions. In October 2019, Chugach entered into APA Amendment No. 2 extending the termination date of the APA from June 30, 2020, to September 30, 2020, and recognizing Eklutna Transmission Assets as acquired assets in recognition of the fulfillment of a condition in the original APA. Additionally, a stipulation was filed with and subsequently accepted by the RCA, which included a commitment from Chugach to establish a $19.0 regulatory asset that would amortize and be recovered over a three-year period immediately following acquisition close. On July 9, 2020, Chugach entered into APA Amendment No. 3 addressing the RCA's conditions which removed provisions regarding Chugach's commitment not to raise base rates as a result of the acquisition, extended the time to close from 120 days to 160 days after RCA approval, removed references to the BRU Fuel Agreement, required the MOA to provide certain copies of easements, reduced the upfront payment to the MOA by $10.0 million, eliminated any upward price adjustment if ML&P's net book value of the purchased assets is greater than $715.4 million at closing, recognized a $36.0 million rate reduction account to be funded by the MOA for the benefit of ML&P legacy customers, and extended the APA termination date to October 31, 2020.

The Eklutna PPA, which became effective upon closing, provides for the purchase of all or a portion of ML&P's share of generation from the Eklutna Hydroelectric Project by Chugach from MOA for a period of 35 years at specified fixed prices each year. In September 2019, Chugach entered into PPA Amendment No. 1, which defines the Eklutna PPA as a wholesale power agreement. In October 2019, Chugach entered into PPA Amendment No. 2 to recognize changes to the dispute resolution procedures. On July 9, 2020, Chugach entered into PPA Amendment No. 3 which recognizes Chugach's right to set-off payments to the extent the MOA does not fulfill its obligations required in the Stipulation and removes references indicating the PPA is a power purchase agreement under Alaska statute.

The PILT Agreement, which became effective upon closing, provides for Chugach to make annual payments in lieu of taxes to the MOA for a period of 50 years based on current millage rates and the adjusted book value of property for ML&P's service territory in existence at the closing as adjusted each year. The PILT Agreement also provides that until December 31, 2033, Chugach shall only collect amounts associated with those annual PILT payments from retail customers in the legacy ML&P territory. Thereafter, the annual PILT payments shall be collected from all Chugach retail customers. In September 2019, Chugach entered into PILT Amendment No. 1 to revise the calculation of PILT to make it consistent with the APA Amendment No. 1. In October 2019, Chugach entered into PILT Amendment No. 2 to remove Chugach's obligation in certain regulatory or bankruptcy proceedings to support and stipulate to the fact that the payments in lieu of taxes are a tax obligation and should be given appropriate priority status based on that fact. On July 9, 2020, Chugach entered into PILT Amendment No. 3, which requires that beginning no later than January 1, 2024, costs incurred by Chugach as a result of the PILT Agreement shall be recovered through base rates charged to all Chugach customers.

On September 30, 2020, Chugach submitted a request to the RCA to temporarily suspend its participation in the Simplified Rate Filing ("SRF") process pending the completion of a general rate case. Chugach has committed and the RCA affirmed that Chugach will file its first general rate case following the acquisition of ML&P by December 31, 2023. Chugach is planning to request RCA approval to re-enter the SRF process after completion of the rate case.

On October 26, 2020, Chugach issued $275,000,000 of First Mortgage Bonds, 2020 Series A, due October 15, 2039 (Tranche A) and $525,000,000 of First Mortgage Bonds, 2020 Series A, due October 15, 2050 (Tranche B), for the purpose of funding the acquisition of certain assets of ML&P from the MOA ("Acquisition"), fund transaction costs relating to the Acquisition, refinance unsecured indebtedness issued to fund costs associated with the Acquisition or reimburse Chugach for other funds applied in connection therewith.

The 2020 Series A Bonds (Tranche A) will mature on October 30, 2039, and will bear interest at 2.38% per annum. Interest will be paid each April 30 and October 30, commencing on April 30, 2021. The 2020 Series A Bonds (Tranche B) will mature on October 30, 2050, and will bear interest at 2.91% per annum. Interest will be paid each April 30 and October 30, commencing on April 30, 2021. The 2020 Series A Bonds (Tranche A) will pay principal on an annual basis beginning on April 30, 2025. The 2020 Series A Bonds (Tranche B) will pay principal between April 30, 2021 and October 30, 2030, and between April 30, 2036 and October 30, 2050. The bonds are secured, equally and ratably with all other obligations outstanding under the Second and Amended Restated Indenture of Trust ("Indenture"). The Indenture grants a lien to the Trustee on substantially all of the tangible assets of Chugach.

The acquisition closed on October 30, 2020. Chugach also entered into a letter agreement regarding the APA with the MOA regarding certain procedural matters related to closing of the acquisition. Additionally, Chugach entered into Amendment No. 4 to the Eklutna Power Purchase Agreement dated September 23, 2020, which modified a clause pertaining to Chugach's portion of the Eklutna Hydroelectric Project, thereby setting a timeline for the parties to come to an agreement within one (1) year of closing on the acquisition of ML&P. Chugach also entered into a side letter to the Eklutna Power Purchase Agreement with the MOA, effective October 30, 2020, addressing the terms and conditions of the interim period between the effective acquisition date of ML&P by Chugach and the effective date of the MEA Eklutna Power Purchase Agreement between the MOA and MEA.

3. GASB TO FASB PRESENTATION

The financial statements of ML&P, as a wholly owned enterprise fund of the MOA, were prepared and presented in accordance with GAAP. ML&P applied all applicable provisions of the Governmental Accounting Standards Board ("GASB") which has authority for setting accounting standards for governmental entities. The application of GASB standards may result in presentations of certain items in these financial statements that differ from another entity, which applies the provisions of a different standard setting body, such as the Financial Accounting Standards Board ("FASB"), or the SEC.

ML&P meets the criteria, and accordingly follows the accounting and reporting requirements applicable to regulated operations. ML&P's rates are regulated by the RCA and as a result, certain presentations may differ from those of a non-regulated entity. The accounting records of ML&P conform to the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"), as prescribed by the RCA.

Certain GASB to FASB Presentation Adjustments

a. Pension and Other Postemployment Benefits

   ML&P participates in the Alaska Public Employees' Retirement System ("PERS") Pension and Other Postemployment Benefits ("OPEB") Plans. ("the Plans"). PERS is a cost-sharing multiple employer plan which covers eligible state and local government employees. The Plans were established and are administered by the State of Alaska. Benefit and contribution provisions are established by State law and may be amended only by the State Legislature.

   To reflect FASB presentation of pension liabilities, deferred outflows related to pensions, of $645,196, included in other long-term assets, and deferred inflows related to pensions, of $932,259, included in deferred inflows of resources, was reclassified to other non-current liabilities on the condensed consolidated pro forma balance sheet. The net effect of this adjustment is an increase of $287,063.

b. Contributions in Aid of Construction ("CIAC")

   ML&P reports both contributed and non-contributed plant assets on its Statements of Net Position as Plant in Service. Funds received as contributions from others for construction and acquisition of those assets is reported as deferred inflows of resources on the Statements of Net Position.

   To reflect FASB presentation, CIAC, of $169,199,321, included in deferred inflows of resources, was reclassified to net utility plant on the condensed consolidated pro forma balance sheet.

c. Restricted Assets

   ML&P reports as current restricted assets amounts required to discharge current restricted liabilities. Among those current restricted liabilities are customer deposits.

   To reflect FASB presentation, restricted equity in general cash associated with customer deposits was reclassified to cash and cash equivalents on the condensed consolidated pro forma balance sheet.

d. Other Financing Uses – Transfers to Other Funds

ML&P reports revenue distributions to the municipal general government and certain other transactions with other funds of the MOA as Transfers to Other Funds.

To reflect FASB presentation, transfers to/from other funds, of $190,311, and Municipal Utility Service Assessment ("MUSA"), of $7,454,377, was reclassified to administrative, general and other on the condensed consolidated pro forma statements of operations.

e. Non-Operating Revenues and Expense

ML&P reports as non-operating revenues those revenues that are earned outside of the normal course of business operating an electric utility. Those include federal Build American Bonds interest subsidies, investment income, pension and OPEB contributions from the state on behalf of ML&P and gain on disposal of assets. ML&P reports certain expenses incurred outside the normal course of business operating an electric utility as non-operating expenses. These include interest expenses, allowance for funds used during construction, amortization of other assets and loss on disposal of property.

To reflect FASB presentation of unamortized debt expense of $1,161,368 and deferred loss on refunding of $645,196 included in other long-term assets was reclassified to unamortized debt issuance costs on the condensed consolidated pro forma balance sheet.

To reflect FASB presentation, the loss on disposal of property, of $458,782, was reclassified from nonoperating margins to administrative, general and other on the condensed consolidated pro forma statements of operations.

To reflect FASB presentation, the amortization of other assets associated with debt issuance costs, of $23,756, and the interest subsidy on Build America Bonds, of $1,837,166, was reclassified from nonoperating margins to interest expense, net, on the condensed consolidated pro forma statements of operations.

f. Asset Retirement Obligation

As a rate regulated utility using the FERC chart of accounts, ML&P has adopted the common utility practice of group depreciation and composite depreciation. Under these methods, when utility plant is retired before or after the average service life of the group is reached, the resulting gain or loss is included in the accumulated depreciation account. The cost of the asset less the salvage value plus the cost of removal of the asset are recorded in the accumulated depreciation account upon retirement. Every five years ML&P commissions a depreciation study and has its depreciation rate approved by the RCA. Those rates typically include an estimated cost of removal for some asset classes. Plant assets are properly reported at cost less approved accumulated depreciation on its Statements of Net Position. This treatment is well accepted utility practice and approved regulatory GAAP by many regulatory commissions, including the RCA, and is in accordance with the FERC Definition 10 in 18 Code of Federal Regulations ("CFR") Part 101 and further confirmed in Docket No. RM02-7-000, Order No. 631, issued April 9, 2002, "Accounting, Financial Reporting and Rate Filing Requirements for Asset Retirement Obligations". ML&P does not record an imputed asset retirement obligation for any asset if it is not required by law to do so.

To reflect FASB presentation of the cost of removal obligation associated with ML&P's electric plant as a liability reclassified from accumulated depreciation included in net utility plant on the condensed consolidated pro forma balance sheet. This adjustment is a preliminary estimate due to the limited availability of information.

g. Future Natural Gas Purchases

To reflect FASB presentation, future natural gas purchases of $18,870,840, included in deferred inflows of resources, was reclassified to deferred credits.

h. Operating and Financing Leases

At this time, we have not identified any operating or financing leases.

4. ACQUISITION PRO FORMA ADJUSTMENTS

The pro forma adjustments, excluding the GASB to FASB presentation adjustments disclosed in note 3 above, to the unaudited condensed combined pro forma financial statements consist of the following:

a. Reflects net utility plant associated with the Ekutna Hydroelectric Project, which was not acquired in the acquisition.

b. Reflects elimination of restricted cash accounts associated with ML&P's debt not acquired in the acquisition.

c. Reflects elimination of ML&P's cash and cash equivalents retained by the MOA at acquisition.

d. Reflects cash received from issuance of 2020 First Mortgage Bonds used to finance the acquisition, less principal and interest payable on the 2020 First Mortgage Bonds within nine months, the purchase price of $749,038,891, and $3.6 million of debt issuance costs paid at closing, plus a working capital adjustment of approximately $3.6 million.

e. Reflects elimination of ML&P debt and debt issuance costs not assumed in the acquisition.

f. Reflects the 2020 First Mortgage Bonds, less a principal payment of $9.0 million and reclassification of $18.0 million in principal to current portion of long-term obligations.

g. Reflects elimination of ML&P accrued interest and addition of three months accrued interest on the 2020 First Mortgage Bonds, less a principal payment of $9.0 million.

h. Reflects the elimination of ML&P equity not acquired in the acquisition.

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i. Reflects the elimination of ML&P net pension liability not assumed in the acquisition.

j. Reflects the $36.0 million rate reduction asset and liability pursuant to conditions of the acquisition, reduced by $9.0 million for nine months of rate reductions.

k. Reflects the assignable margins attributable to nine months of ML&P operations and acquisition costs from the unaudited pro forma condensed consolidated statements of operations.

l. Reflects recognition of the $42.4 million regulatory asset recorded at closing representing the purchase price exceeding the net book value of the assets acquired that will be recovered in rates subsequent to 2022 and nine months amortization of the $19.0 million regulatory asset related to acquisition and integration costs recovered in rates through 2022 per RCA order.

m. Reflects $3.6 million of debt issuance costs incurred at closing less nine months of amortization.

n. Reflects the elimination of interest, interest subsidies and amortization of debt issuance costs associated with ML&P's long-term debt prior to acquisition.

o. Reflects the nine months of interest associated with the 2020 First Mortgage Bonds issued to acquire ML&P and finance associated acquisition and integration costs, as well as nine months amortization of debt issuance costs associated with these bonds.

p. Reflects the elimination of MUSA and recognition of PILT for nine months.

q. Reflects the elimination of depreciation expense associated with the Ekltuna Hydroelectric Project not acquired in the acquisition.

r. Reflects nine months of costs associated with the Eklutna Power Purchase Agreement.

s. Reflects nine months amortization of $19.0 million regulatory asset associated with acquisition and integration costs and discussed in note 4l above.