COLORADO SPRINGS UTILITIES

Nature of the Utilities

Colorado Springs Utilities, created by the home rule charter of the City (the "Charter") consists of a water system (the "Water System"), an electric light and power system (the "Electric System"), a gas system (the "Gas System"), a wastewater system (the "Wastewater System"), a streetlight system (the "Streetlight System"), and other systems designated in accordance with the Charter (collectively, the "System"). The Utilities is wholly owned by the City and constitutes an enterprise under certain Colorado Constitution and Charter provisions described below under "—Tax and Spending Limits." The Utilities operates primarily through functional divisions responsible for planning, financing, constructing, operating, customer service, environmental, strategy, and external affairs associated with the delivery of electric, gas, water, wastewater and streetlight services.

The service areas of the System include the City, Manitou Springs, the City of Fountain, and many of the suburban residential areas surrounding the City. The military installations of Fort Carson, Peterson and the Academy receive water and electric service and gas supply and transportation from the System, and Peterson also receives wastewater treatment service from the System.

The City's general fund is the sole customer of the Streetlight System.

The following table summarizes information concerning operating revenues, operating income (loss) and gross book value of plant for the electric, gas, water, wastewater, and streetlight operations of the Utilities for the fiscal year ended December 31, 2016.

2016 Summary of Business Segments

	Operating Revenues		*Operating Expenses*		*Operating Income (Loss)*	*Utilities Plant Gross Book Value*[1]	
	($000)	*% of Total*	*($000)*	*% of Total*	*($000)*	*($000)*	*% of Total*
Electric	$422,285	52.3%	$323,143	50.5%	$ 99,142	$2,441,810	39.7%
Gas[2]	136,144	16.9	120,881	18.9	15,263	383,694	6.2
Water[3]	177,251	21.9	139,893	21.9	37,358	2,372,364	38.6
Wastewater	68,017	8.4	51,147	8.0	16,870	899,296	14.6
Streetlight	4,129	0.5	4,925	0.8	(796)	48,732	0.8
Total	$807,826	100.0%	$639,989	100.0%	$ 167,837	$6,145,896	100.0%
Less: Interdepartmental Sales	(14,534)		(14,546)		12		
Net Total	$793,292		$625,443		$ 167,849		

(1) Total Net Utilities Plant (excluding water component units) is $3,940,502,289. This amount represents $5,938,610,494 in Gross Utilities Plant plus $207,286,400 in Construction Work in Progress, less Accumulated Depreciation and Amortization of $2,205,394,605. See Note 5 in the 2016 Audited Financial Statements attached hereto as Appendix A.

(2) The gas information excludes amounts attributable to the Public Authority for Colorado Energy described in Note 18 in the 2016 Audited Financial Statements. For a description of Public Authority for Colorado Energy see page 56 in the 2016 Audited Financial Statements attached hereto as Appendix A.

(3) The water information excludes amounts attributable to the water component units described in Note 18 in the 2016 Audited Financial Statements. For descriptions of the component units see page 57 in the 2016 Audited Financial Statements attached hereto as Appendix A.

Surplus Payments

The Charter provides that the funds of the Utilities are to be kept separate from all other funds of the City and that the net earnings of the Utilities are to be appropriated for the necessary requirements of the Utilities. The Charter also provides that any surplus remaining after meeting the necessary requirements of the Utilities may be appropriated to the general revenues of the City by the City Council of the City (the "City Council") in its annual budget and appropriation ordinance. Pursuant to this authority, the City Council has appropriated annually to the City's general fund certain amounts, denoted as surplus payments. These payments are calculated at a fixed rate per kWh of electricity and a fixed rate per Mcf at 14.65 p.s.i.a. of natural gas applied to all inside City sales volumes, without exclusion for interdepartmental sales. The City Council is currently considering modifying how surplus payments are calculated. Any such change would likely increase the size of the surplus payment, though the magnitude of such increase is not known at this time. **[To up be updated if a final decision is made prior to posting.]**

Total surplus payments made by the Utilities to the City amounted to $31,454,151 in 2014, $31,251,420 in 2015, and $31,408,269 in 2016.

City Governance

The City is governed by mayor-council form of governance. Under this form of governance, the Mayor appoints all department directors except for the City Auditor, the Council Administrator, and the Utilities Executive Director (the "Chief Executive Officer"), who are appointed by the City Council. The Mayor serves as an ex-officio and non-voting member of the Board of Directors of the Utilities (the "Utilities Board"), participates in such meetings and attends Executive Sessions of the Utilities Board.

The City Council has all rate making authority for the Utilities, and the Mayor does not have any veto authority over rate decisions.

Management and Operation of the Utilities

The Chief Executive Officer has authority over the management, finances and operation of the Utilities. The City Council, through its role as the Utilities Board, governs the management and operations of the Utilities through established written policies. The present members of the Utilities Board, their occupations, and the dates their current terms expire are as follows:

Member	***Occupation***	***Expiration of Term***
Tom Strand (Chair)	U.S. Air Force JAG, Retired	April 2019
Andy Pico (Vice Chair)	Defense Contractor	April 2021
David Geislinger	Attorney (licensed but inactive), Hospital Chaplain, Deacon	April 2021
Merv Bennett	Nonprofit CEO, Retired	April 2019
Yolanda Avila	Criminal Defense Investigator/Community Leader	April 2021
Jill Gaebler	Nonprofit/Education Leader	April 2021
Richard Skorman	Business Owner	April 2021
Don Knight	U.S. Air Force/Defense Contractor, Retired	April 2021
Bill Murray	U.S. Army, Retired; Defense Consultant	April 2019

The Utilities Policy Advisory Committee ("UPAC") is comprised of seven regular members appointed by the Utilities Board. The Utilities Board directs UPAC to study specific issues or policies and provide recommendations to the Utilities Board. The present members of UPAC, their occupations, and the dates their current terms expire are as follows:

Member	***Occupation***	***Expiration of Term***
Richard Kramer (Chair)	Financial/Business	September 2018
Rex Adams (Vice Chair)	Financial/Business	September 2017
Joseph Mark	Engineering	September 2017
Balu Bhayani	Engineering	September 2018
Scott Harvey	Engineering	September 2018
Thomas Taylor	Financial/Business, Engineering	September 2017
James Colvin	Financial/Business	September 2019

Management Staff

The Utilities consists of the following six functional divisions: Water Services Division; Planning and Finance Division; Customer and Corporate Services Division; Energy Services Division; Environment, Health & Safety Division; and Strategy and External Affairs Division. Members of the officer team, their prior positions with the Utilities, and the years in which they were first employed by the Utilities are as follows:

Member	***Recent Positions Held with the Utilities***		***Year Employed***
Jerome Forte, Jr.	1/06 to present	Chief Executive Officer	2002
	8/05 to 1/06	Interim Chief Executive Officer	
	1/02 to 8/05	Chief Operating Officer	
William J. Cherrier	1/09 to present	Chief Planning and Finance Officer	2005
	8/05 to 1/09	General Manager, Financial Services	
	7/05 to 8/05	General Accounting Manager	
Carl Cruz	2/09 to present	Chief Customer and Corporate Services Officer	2000
	4/08 to 2/09	General Manager, Field Service and System Quality Departments	
	7/01 to 4/08	Manager, Field Service Department	
Daniel J. Higgins	1/16 to present	Chief Water Services Officer	1998
	8/15 to 1/16	Manager, Energy Regulatory and Compliance	
	3/14 to 7/15	Interim General Manager, Energy Supply	
	10/07 to 3/14	Manager, Southern Delivery System	
	3/04 to 10/07	Manager, PLE Project Management	
	10/01 to 3/04	Engineer Principal/Managing	
	2/01 to 10/01	Senior Project Engineer	
Sherri Newell Wilkinson	6/01 to present	Chief Strategy and External Affairs Officer	1994
	11/94 to 6/01	Marketing Division Manager	
David Padgett	7/11 to present	Chief Environment, Health and Safety Officer	1985
	2/11 to 6/11	Environment, Health and Safety Manager	
	10/10 to 2/11	Interim Chief Water Services Officer	
	5/10 to 10/10	Environment, Health and Safety Manager	
	6/06 to 5/10	Environment Services Department Manager	
	9/05 to 5/06	Interim Planning and Engineering General Manager	
Eric Tharp	10/14 to present	Chief Energy Services Officer	2014

Employees

As of December 31, 2016, the Utilities employed 1,758 full-time employees. The Utilities management believes that relations with its employees are satisfactory.

Retirement Plans

The Utilities is a member of and contributes to the Local Government Division Trust Fund of the Public Employees' Retirement Association of Colorado ("PERA"), a multi-employer defined benefit plan. During 2014, 2015, and 2016 the Utilities contributed $19,362,364, $19,687,959 and $20,447,450 respectively, to the PERA plan, which was equal to the Utilities' annual required contribution for each of those years. These amounts include amounts contributed to the Health Care Trust Fund discussed below under "Postemployment Health Care Plan." The rates for employer and employee contributions to PERA are established under State statutes and the Utilities believes its contribution in 2016 complied with such statutes. The Utilities' contribution rate may fluctuate in accordance with the funded (or unfunded) status of the plan. The current statutory employer contribution rate is 8.0% of covered salary for plan members and 10.0% of covered salary for the Utilities. For 2017, the Utilities has budgeted a contribution to the PERA plan of $21,056,374.

In addition, the Utilities is currently required to contribute an amortization equalization disbursement of 2.2% of the employer's total payroll and a supplemental amortization equalization disbursement of 1.5% of the employer's total payroll, which is included in the total contribution rate of 13.7% of covered salary. The amortization equalization disbursement and the supplemental amortization equalization disbursement will remain at that level until adjusted in accordance with Colorado law. Effective January 1, 2011, decreases by 0.5% for each disbursement are mandated when the Local Government Division Trust Fund's year-end funded status reaches 103.0%, and increases by 0.5% for each disbursement are mandated when the Local Government Division Trust Fund funded status reaches 90.0% and subsequently falls below 90.0%.

The supplemental amortization equalization disbursement is to be financed from monies intended for employee salary increases, to the extent permitted by law.

PERA's assets and liabilities are divided amongst several trust funds, with the Utilities participating in the Local Government Division Trust Fund and the Health Care Trust Fund. The Health Care Trust Fund is discussed below under "Postemployment Health Care Plans." According to PERA's Comprehensive Annual Financial Report for the year ended December 31, 2016 (the "Report"), the Local Government Division Trust Fund had an unfunded actuarial accrued liability of $1,333,855, and the ratio of the actuarial value of assets to the actuarial accrued liability was 74.4%. These amounts are based on the actuarial and other assumptions set forth in the Report, including an assumed investment rate of return of 7.25% per year.

PERA does not break out the funding status for each participating entity in the Local Government Division Trust Fund; therefore, it may not be possible to determine the City's allocable share of the unfunded actuarial accrued liability of the Local Government Division Trust Fund. For additional information about PERA and the Local Government Division Trust Fund, see Note 12 to the Financial Statements included in Appendix A. A copy of the Report can be obtained from PERA at www.copera.org or by writing to PERA at 1300 Logan Street, Denver, Colorado 80203. Investors are advised to review the Report to obtain information about the funding status of the Local Government Division Trust Fund and the assumptions used to calculate such funding status.

Effective January 1, 2015, the Utilities adopted Governmental Accounting Standards Board Statement No. 68, Accounting and Financial Reporting for Pensions ("GASB 68") and Governmental Accounting Standards Board Statement No. 71, Pension Transition for Contributions made Subsequent to Measuring Date – An Amendment of GASB Statement No. 68 ("GASB 71), to its audited financial statements. The Utilities did not restate to prior periods, recognizing the cumulative effect of these changes on the 2015 Statement of Revenues, Expenses and Changes in Net Position. See Note 19 and the Required Supplementary Information in the audited financial statements attached hereto as Appendix A.

Postemployment Health Care Plan

The Utilities contributes to the Health Care Trust Fund, a cost-sharing, multiple-employer postemployment health care plan administered by PERA. The Health Care Trust Fund provides a health care premium subsidy to PERA participating benefit recipients and their eligible beneficiaries. According to the Report, the Health Care Trust Fund had an unfunded actuarial accrued liability of $1,286,612 as of the end of 2016, and the ratio of the actuarial value of assets to the actuarial accrued liability was 17.4%. These amounts are based on the actuarial and other assumptions set forth in the Report, including an assumed investment rate of return of 7.25% per year.

The Utilities is required to contribute at a rate of 1.02% of covered salary for all PERA members. This amount is included in the statutory employer contribution rate of 10.0% of covered salary discussed above under "Retirement Plans." The Utilities contribution to the Health Care Trust Fund is included in the total contribution to the PERA plan. No employee contributions are required. The Utilities' contributions to the Health Care Trust Fund for the years ended December 31, 2014, 2015 and 2016 were $1,441,568, $1,465,778 and $1,522,365 respectively, equal to the required contributions for each year.

PERA does not breakout the funding status for each participating entity in the Health Care Trust Fund; therefore, it is not possible to determine the City's allocable share of the unfunded actuarial accrued liability of the Health Care Trust Fund. For additional information about the Health Care Trust Fund see Note 13 to the Financial Statements included in Appendix A. A copy of the Report can be obtained from PERA at www.copera.org or by writing to PERA at 1300 Logan Street, Denver, Colorado 80203. Investors are advised to review the Report to obtain information about the funding status of the Health Care Trust Fund and the assumptions used to calculate such funding status.

In accordance with the City Code, the Utilities also offers a health care plan for retirees. Employees eligible to retire prior to January 1, 1979 receive this health care plan without costs to the employee (full coverage) and those eligible to retire after January 1, 1979 and hired prior to August 1, 1988 receive a limited Utilities' contribution (partial coverage) not to exceed $91.40 per month. During 2016, the Utilities made $1,238,271 in contributions to the plan consisting of payments totaling $1,186,290 paid directly to employees/surviving spouses with partial coverage and $51,351 to employees with full coverage. In addition to regular medical insurance subsidies, Utilities also funds a Medicare supplement for eligible retirees, and in 2016, Utilities paid a total of $21,400 to eligible retirees. Post-retirement health care benefits are considered to be unfunded since there are no dedicated assets and retiree benefits are paid annually in an amount equal to the benefits distributed or claimed in that year (pay-as-you-go basis).

As of January 1, 2015, the most recent actuarial valuation date, the OPEB obligation for the Utilities had an unfunded actuarial accrued liability of $20,726,000.

For more information, see Note 14 to the Financial Statements included in Appendix A.

Summary of Operations

The following summary of operations was derived from the audited financial statements of the Utilities for fiscal years ended December 31, 2012 to 2016 (not taking into account water component units such as joint water authorities). For water component unit information, see Notes 1 and 17 to the Financial Statements included in Appendix A.

Information presented for the six-month periods ended June 30, 2016 and June 30, 2017 was derived from the Utilities' internally prepared financial statements. Such financial statements are unaudited, but, in the opinion of management of the Utilities, reflect all adjustments (none of which was other than a normal recurring adjustment (accrual) necessary for a fair presentation of the results of operations for such interim periods). The results of operations for an interim period should not be considered indicative of the results for a full fiscal year.

SUMMARY OF OPERATIONS

	Year ended December 31					*Six Months ended June 30*	
	2012	***2013***	***2014***	***2015***	***2016***	***2016***	***2017***
Operating Revenues[1]	$ 849,746,643	$ 823,759,529	$ 868,847,747	$ 830,820,813	$ 793,292,942[2]	$371,589,879	$ 414,370,759
Operating and Other Expenses:							
Operating Expenses:[1]							
Production and Treatment	$ 144,360,585	$ 153,634,499	$ 155,521,610	$ 137,547,139	$136,020,467	$ 62,121,720	$ 70,224,010
Purchased Power, Gas and Water for Resale	188,627,034	168,003,399	184,585,684	121,158,448	103,729,998	51,890,371	64,489,325
Transmission and Distribution	36,386,480	39,342,897	40,281,124	40,469,104	41,359,461	19,478,008	20,090,251
Maintenance	61,793,083	63,023,290	61,436,693	61,106,731	63,173,224	26,857,344	29,742,518
Administration and General	96,185,140	93,143,285	95,046,556	102,570,936	119,931,173	52,211,814	55,673,749
Customer Service and Information	10,308,869	11,027,005	10,354,189	11,606,789	12,725,576	5,452,417	6,477,755
Customer Accounting and Collection	20,283,445	20,362,110	19,385,277	18,852,540	18,510,043	9,088,982	9,391,609
Products and Services	61,831	12,105	6,317	625	24	(267)	--
Franchise Taxes	288,408	289,996	303,178	303,927	299,095	184,546	193,435
Depreciation and Amortization	116,184,836	118,430,128	119,842,074	120,099,931	129,693,856	61,437,539	75,903,614
Total Operating Expenses	$ 674,479,711	$ 667,268,714	$ 686,762,702	$ 613,716,170	$ 625,442,917	$ 288,722,474	$ 332,186,266
Operating Income	$ 175,266,932	$ 156,490,815	$ 182,085,045	$ 217,104,643	$ 167,850,025	$ 82,867,405	$ 82,184,493
Non-Operating Revenues (Expenses)							
Derivatives Instruments Gain/Loss[3]	$ 6,176,646	$ (67,935,921)	$ (30,067,132)	$ 3,462,806	$ 19,107,213	$ (22,082,281)	$ 568,105
Investment Income	2,688,846	2,322,578	2,184,880	2,207,045	3,125,982	1,566,080	902,303
Other Revenues[4]	13,052,546	16,679,905	16,107,988	13,306,323	17,766,122	5,872,398	5,440,363
Other Expenses[6]	(5,298,844)	(5,276,473)	(3,560,054)	(1,951,162)	(2,715,281)	(1,019,591)	(951,834)
Interest Expense[6]	(88,871,887)	(81,468,977)	(77,485,447)	(73,593,102)	(86,168,070)	(41,912,530)	(49,414,620)
Total Non-Operating Revenues (Expense) [6]	$ (72,252,693)	$ (135,678,888)	$ (92,819,765)	$ (56,568,090)	$ (48,884,034)	$ (57,575,924)	$ (43,455,683)
Income (Loss) before Contributions, Transfers, and Extraordinary Items[6]	$ 103,014,239	$ 20,811,927	$ 89,265,280	$ 160,536,553	$ 118,965,991	$ 25,291,481	$ 38,728,810
Contributions in Aid of Construction	47,142,662	44,490,038	47,073,875	44,681,903	52,833,199	21,792,222	29,550,306
Transfers Out – Surplus Payments to the City	(30,595,266)	(31,844,422)	(31,454,151)	(31,251,419)	(31,408,269)	(16,010,678)	(15,573,437)
Transfers – Other	(639,616)	(308,288)	(601,481)	276,960	(128,425)	(141,206)	(180,978)
Extraordinary Expense[7][8]	--	(507,495)	--	--	(9,810,541)	--	--
Change in Net Position[6]	$ 118,922,019	$ 32,641,760	$ 104,283,523	$ 174,243,997	$ 130,451,955	$ 30,931,819	$ 52,524,701
Total Net Position, January 1[5]	$1,334,433,847	$1,453,355,866	$1,485,997,626	$1,397,645,665	$1,571,889,662	$1,571,889,662	$1,702,341,617
Total Net Position, December 31[6]	$1,453,355,866	$1,485,997,626	$1,590,281,149	$1,571,889,662	$1,702,341,617	$1,602,821,481	$1,754,866,318

---

(1) Operating Revenues and Operating Expenses are shown net of interdepartmental sales transactions in the following amounts: 2012 - Operating revenue elimination ($19,907,783)/Operating expense elimination $19,907,783; 2013 - Operating revenue elimination ($15,248,365)/Operating expense elimination $15,248,365; 2014 - Operating revenue elimination ($14,335,613)/Operating expense elimination $14,502,377; 2015 – Operating revenue elimination ($14,607,281)/Operating expense elimination $14,607,281; and 2016 – Operating revenue elimination ($14,534,007)/Operating expense elimination $14,534,007.

(2) The reduction in the Utilities' Operating Revenues from 2015-2016 was primarily due to a reduction in Gas Revenues and Electric Revenues. See "THE GAS SYSTEM – Gas Sales and Revenues" and "THE ELECTRIC SYSTEM Electric Sales and Revenue."

(3) Includes the following unrealized gains or losses attributable to energy swaps: 2012 - $6,786,466; 2013 - $0; 2014 - $0; 2015 - $0 and 2016 - $0.

(4) Includes accrued interest earnings subsidies from the United State Treasury for previously issued utilities system revenue bonds designated as "Build America Bonds": 2012 - $8,469,392; 2013 - $7,875,124; 2014 - $7,933,210; 2015 - $7,949,572 and 2016 - $7,953,143.

(5) Beginning year net position for 2015 has been restated from $1,590,281,149 to $1,397,645,665 to reflect the implementation of GASB 68 and GASB 71. For more information see Note 19 of the 2016 Audited Financial Statements.

(6) Effective December 15, 2012, the Utilities adopted GASB 65. Implementation of GASB 65 resulted in a revision of Other Expenses in the amount of $(1,511,099) and Interest Expense in the amount of $692,522 for the period ending December 31, 2012.

(7) In September 2013, significant rainfall and flooding occurred in Utilities' service area and surrounding areas causing significant damage to some of the Utilities' infrastructure and assets, including some which were permanently impaired. This rainfall and subsequent flooding were rare and unusual based upon historical rainfall patterns in the Utilities' service area. In accordance with GASB 42, an extraordinary expense has been recognized. For more information see Note 19 in the 2013 Audited Financial Statements.

(8) In 2016, Drake unit 5 was decommissioned. In accordance with GASB 42, an extraordinary expense of $9,810,541 has been recognized. For more information see Note 5 in the 2016 Audited Financial Statements.

Pursuant to GASB 34, the audited financing statements attached as Appendix A hereto include a management discussion and analysis for the fiscal year ended December 31, 2016.

For the six month period ended June 30, 2017, the Total Net Position increased $152.0 million over the same period one year ago. Increased Operating Revenues were offset by increased Depreciation and Amortization expenses, Purchased Power, Gas and Water for Resale Expenses, and Production and Treatment expenses. In Non-Operating Revenues/(Expenses) there was an increased value of Derivative Instruments which was offset by an increase in Interest expense.

For the six month period ended June 30, 2017, Operating Revenues increased $42.8 million over the same period one year ago. Depreciation and Amortization expenses increased by $14.5 million, Purchased Power, Gas and Water for Resale expenses increased by $12.6 million, Production and Treatment expenses increased by $8.1 million. Total Operating Income decreased by $0.7 million.

For the six month period ended June 30, 2017, Total Non-Operating expenses decreased by $14.1 million compared to the same period one year ago. A Derivatives Instrument fair value gain of $0.6 million was recognized during the first 6 months of 2017 as compared to a fair market value loss of $22.1 million recognized during the first 6 months of 2016. The change in fair value of Derivative Instruments is a non-realized, non-cash expense recognized due to market conditions during the period. Interest expense increased by $7.5 million. Income before Contributions & Transfers increased by $13.4 million.

Financial Statements

The Utilities' Statements of Net Positions for the periods ended December 31, 2014, December 31, 2015 and December 31, 2016, Statements of Revenues, Expenses and Changes in Net Position and Statements of Cash Flows for the years ended December 31, 2014 through December 31, 2016 have been audited by Baker Tilly Virchow Krause, LLP, the Utilities' independent certified public accountants. The Financial Statements and the report of the independent certified public accountants as of and for the years ended December 31, 2015 and 2016 are included as Appendix A to this Official Statement.

Outstanding Utilities Revenue Bonds and Other Obligations

Upon issuance of the Bonds, $______________* in aggregate principal of Parity Bonds (including the Bonds) will be outstanding which have a parity lien on the Net Pledged Revenues. The City is prohibited from issuing additional bonds with a lien on the Net Pledged Revenues which is superior to the Parity Bonds (including the Bonds).

The City has entered into a $60.0 million revolving loan agreement with U.S. Bank National Association dated as of September 8, 2016, that currently expires on September 9, 2019 (the "Revolving Loan Agreement"). The City may receive advances up to the maximum amount of the Revolving Loan Agreement in order to fund the Utilities' operating needs and normal expenditures including, without limitation, regularly scheduled capital expenses. The City's repayment obligations under the Revolving Loan Agreement is limited to the Net Pledged Revenues on a subordinate basis to the Parity Bonds and certain related obligations. The City has entered into other similar revolving loan agreements beginning in 2002 and, to date, the City has not initiated advances under any such agreement.

The Utilities has authorized Commercial Paper Notes in the maximum principal amount of $150,000,000, of which $-0- is expected to outstanding upon issuance of the Bonds. The lien on the Net Pledged Revenues which secures the Commercial Paper Notes is subordinate to the lien thereon securing the Parity Bonds (including the Bonds), and on a parity with the lien thereon securing the City's repayment obligations under the Revolving Loan Agreement.

* *Preliminary; subject to change*

Liquidity/Support Facilities

The City has the following outstanding Parity Bonds and Commercial Paper which are supported by Support Facilities. These Support Facilities are listed in the table below.

Support Facilities

Name of Support Facility Provider	*Series of Bonds*	*Total Outstanding Amount of Associated Bonds or Commercial Paper*	*Ratings of Provider*[1]	*Stated Termination Date(s) of Support Facility(ies)*
Bank of America N.A.	Commercial Paper	$100,000,000 [2]	P-1/A-1/F1	12/7/2018
Bank of America N.A.	2004A	87,350,000[3]	P-1/A-1/F1	08/01/2019
Barclays	2010C[4]	_________	__/__/__	07/__/2021[4]
JPMorgan Chase Bank, N.A.	2006A	_________	P-1/A-1/F1+	09/15/2018
Landesbank Hessen-Thueringen Girozentrale	2000A, 2006B	179,100,000[5]	P-1/A-1/F1+	11/30/2020; 09/13/2021
Mizuho, Ltd.	2002C, 2005A	115,600,000[6]	P-1/A-1/F1	09/14/2019; 09/15/2019
Sumitomo Mitsui Banking Corporation	2007B, 2009C[7]	__________[8]	P-1/A-1/F1	__/__/2022; 09/16/2022[7]
U.S. Bank National Association	2008A, 2012A	89,785,000[9]	P-1/A-1+/F1+	09/01/2020; 09/14/2018
Wells Fargo Bank, National Association	2007A	65,770,000	P-1 /A-1+/F1+	09/22/2020

(1) Short-term ratings by Moody's Investors Service Inc. ("Moody's"), Standard and Poor's Ratings Services, a Standard & Poor's Financial Services LLC business ("S&P"), and Fitch Ratings, respectively.
(2) All outstanding Commercial Paper is expected to be refunded with proceeds of the Series 2017A-2 Bonds.
(3) The Utilities currently expects to refund all of the 2004A Bonds with proceeds of the Series 2017A-3 Bonds and terminate the related Support Facility and interest rate swap agreement.
(4) The current support facility related to these bonds is provided by JPMorgan Chase Bank, N.A. On October 25, 2017, the Utilities expect to replace such support facility with one provided by Barclays Bank PLC.
(5) $110,000,000 associated with the 2000A Bonds and $69,100,000 associated with the 2006B Bonds.
(6) $27,055,000 associated with the 2002C Bonds and $88,545,000 associated with the 2005A Bonds.
(7) On September 18, 2017, the Utilities expect to replace the existing support facility related to these bonds with one provided by Sumitomo Mitsui Banking Corporation.
(8) $_________ associated with the 2007B Bonds and $___________ associated with the 2009C Bonds.
(9) $43,520,000 associated with the 2008A Bonds and $46,265,000 associated with the 2012A Bonds.

For a description of some of the risks in connection with these Support Facilities, see "INVESTMENT CONSIDERATIONS—Risks Regarding Liquidity Facilities."

The obligation of the City to make payments under any of the Support Facilities for the Parity Bonds discussed above is secured by a lien on the Net Pledged Revenues which is on parity with the lien thereon of the Parity Bonds (including the Bonds). The obligation of the City to make payments under the Support Facility for the Commercial Paper discussed above is secured by a lien on the Net Pledged Revenues which is subordinate to the lien thereon of the Parity Bonds (including the Bonds).

Interest Rate Swap Agreements

Summary of Current Interest Rate Swap Agreements. The City, on behalf of the Utilities, has entered into various interest rate swap agreements. Set forth below is a summary of the interest rate swap agreements entered into by the City on behalf of the Utilities.

Interest Rate Swap Agreements

Name of Swap	***Counterparty***	***Counterparty Rating***[(1)]	***Notional Amount***	***Fixed Rate Payable by the City***	***Variable Rate Payable to the City***	***Associated Bond Issue***	***Effective Date***	***Termination Date***	***Mark to Market Value as of 6/30/17***[(4)]
2004 SIFMA Swap[(1)]	JP Morgan Chase Bank	Aa3/A+/AA-	$ 87,350,000	4.1120%	SIFMA[(2)]	2004A	08/18/04	11/1/23	$ (8,074,975)
2005 SIFMA Swap	Bank of America, N.A.	A1/A+/A+	64,818,750	4.7099	SIFMA	2005A	09/15/05	11/1/35	(17,625,987)
2005 SIFMA Swap	J. Aron & Co	A3/BBB+/A[(3)]	21,606,250	4.7099	SIFMA	2005A	09/15/05	11/1/35	(5,875,329)
2006 Refunding LIBOR Swap	JP Morgan Chase Bank	Aa3/A+/AA-	59,200,000	4.4810	68% of LIBOR	2006A	08/24/06	11/1/25	(12,651,440)
2006 New Money LIBOR Swap	Morgan Stanley Capital Group Inc.	A3/A+/A[(3)]	40,455,000	4.1185	68% of LIBOR	2006B	09/14/06	11/1/36	(10,637,312)
2006 New Money LIBOR Swap	JP Morgan Chase Bank	Aa3/A+/AA-	26,970,000	4.1185	68% of LIBOR	2006B	09/14/06	11/1/36	(7,091,542)
2007 New Money LIBOR Swap	J. Aron & Co	A3/BBB+/A[(3)]	38,412,000	3.1980	68% of LIBOR	2007A	09/13/07	11/1/37	(6,528,433)
2007 New Money LIBOR Swap	Morgan Stanley Capital Group Inc.	A3/A+/A[(3)]	25,608,000	3.1980	68% of LIBOR	2007A	09/13/07	11/1/37	(4,352,289)
2007 Refunding SIFMA Swap	The Bank of New York Mellon	Aa2/AA-/AA-	87,275,000	5.2950	SIFMA	2007B	10/01/07	11/1/26	(23,065,260)
2008 SIFMA Swap	Bank of America, N.A.	A1/A+/A+	42,415,000	4.2686	SIFMA	2008A	09/12/08	11/1/38	(10,813,572)
2009 LIBOR Swap	Wells Fargo Bank, N.A.	Aa2/AA-/AA	59,650,000	5.4750	68% of LIBOR	2009C	10/01/09	11/1/28	(22,447,421)
2010 LIBOR Swap	Morgan Stanley Capital Group Inc.	A3/A+/A[(3)]	44,135,000	3.8807	68% of LIBOR	2010C	10/26/10	11/1/40	(11,966,427)
2012 LIBOR Swap	Morgan Stanley Capital Group Inc.	A3/A+/A[(3)]	45,235,000	4.0242	68% of LIBOR	2012A	03/15/12	11/1/41	(13,505,105)
Total Notional Amount of Interest Rate Swaps			$ 643,130,000						

(1) The Utilities currently expects to refund the outstanding 2004A Bonds with proceeds of the Series 2017A-3 Bonds and to terminate this interest rate swap agreement.
(2) If SIFMA averages more than 7% for 180 consecutive calendar days during the term of the 2004 SIFMA Swap, the 2004 SIFMA Swap will terminate by its terms and no payments by either party will be due.
(3) Ratings at 06/30/2017 of the respective parent companies by Moody's, S&P and Fitch, respectively.
(4) Source: George K. Baum & Company, a third party valuation service provider. The Mark to Market values shown on this table generally represent the difference between the present value of the fixed rate payments to be made by the City and the present value of the variable rate payments to be made by the applicable swap counterparty, as of the date noted. When the present value of the payments to be made by the City exceeds the present value of the payments to be made by the applicable counterparty, the applicable swap agreement has a negative Mark to Market value to the City. When the present value of the payments to be made by the applicable counterparty exceeds the present value of the payment to be made by the City, the applicable swap agreement has a positive Mark to Market value to the City. If at the time of termination the applicable swap agreement has a negative Mark to Market value to the City, the City would be liable to the counterparty for a payment equal to such value. None of the counterparties has the right to terminate the applicable swap agreement unless the City is in default in its obligations under the swap agreement. The Mark to Market values are shown for informational purposes only and, unless the applicable swap agreement is terminated, do not impact the financial condition of the Utilities.

Risks Associated with Collateral Posting. The swap agreements discussed above have provisions relating to collateral posting by each party. Collateral postings are required to protect either party from risk of default on the financial derivatives used in the hedging transaction. As the mark to market value of the financial derivative changes according to market conditions, the party incurring a "negative" mark to market position on the financial instrument will be required to post collateral as the negative value reaches predefined thresholds. Specifically, the Utilities may be obligated to post collateral with the applicable counterparty if the market value of an agreement decreases according to market conditions. Conversely, as the market value of an agreement increases, the mark to market value favors the Utilities and the Utilities may require the counterparty to post collateral. If an agreement is terminated prior to its stated expiration date due to default, any collateral posted by a party would be retained by the other party. As of June 30, 2017, the City had posted $20.7 million in collateral, with the various counterparties to the interest rate swap agreements discussed above.

Currently, the Utilities has no existing gas hedge agreements. For a discussion of the Utilities' gas hedge program, see "THE GAS SYSTEM—Gas Price Hedge Program."

Priority of Interest Rate Swap Payment Obligations. The obligation of the City to make payments under any of the interest rate swap agreements discussed above, other than termination payments, is secured by a lien on the Net Pledged Revenues which is on parity with the lien thereon of the Parity Bonds (including the Bonds). The obligation of the City to make any termination payments under any of the interest rate swap agreements discussed above is payable from surplus revenues remaining after payment on Parity Bonds (including the Bonds) and subordinate lien bonds, including the Commercial Paper Notes.

Debt Service Reserve Surety Providers

A portion of the outstanding Parity Bonds are secured by reserve funds that have been funded with debt service reserve surety policies provided by Assured Guaranty Municipal Corp. ("AGMC") (as successor to Financial Security Assurance Inc.), and National Public Finance Guarantee Corporation ("NPFGC") (as successor to MBIA Insurance Corporation) in lieu of cash deposits. Each series of Parity Bonds is secured by its own reserve fund. The total face amount of the reserve fund surety policies provided by AGMC is $11,687,443, and the total face amount of reserve fund surety policies provided by NPFGC is $11,509,341. In the event that there are insufficient Net Pledged Revenues available to pay the debt service on the Parity Bonds which are secured by such surety policies, it may become necessary for the City to draw upon its surety policies in order to make a portion of such debt service payments. In the event that AGMC or NPFGC fails to honor such a draw, the Bonds could be negatively impacted; however, the full extent of such impact cannot be measured at this time. The City has no obligation to replace any of the providers of the debt service reserve surety policies or deposit additional cash, securities, or debt service reserve surety policies into reserve funds if the respective ratings of the providers are lowered. While the reserve funds containing the City's debt service reserve surety polices do not secure the Bonds, the Parity Bonds that are secured by such reserve funds have a parity lien upon the Net Pledged Revenues and a default under any of the Parity Bond ordinances for failure to pay debt service on such Parity Bonds would be a default under the Bond Ordinance.

Other Fixed Cost Obligations

In addition to the Parity Bonds, the City has other fixed cost obligations relating to the Utilities. These include, but are not limited to, payments to the authorities in which the City and/or the Utilities is a member, and payments to the U.S. Department of Energy, Western Area Power Administration ("WAPA"), and payments to General Electric International, Inc. pursuant to a maintenance contract for the Utilities' Front Range Power Plant. These payments are primarily treated as operation and maintenance expenses of the System and are therefore payable prior to debt service on the Parity Bonds.

For the fiscal year ended December 31, 2016, the City made the following payments pursuant to these obligations: (a) $5,580,130 to Fountain Valley Authority; and (b) $6,183,918 to WAPA. The Utilities also estimates that it will pay $5,579,774 and $5,731,532 to Fountain Valley Authority and WAPA, respectively, in the fiscal year ending December 31, 2017. In December 2010, the City acquired Front Range Power and the Front Range Power Plant. The City has a contract with General Electric International, Inc. for maintenance of the Front Range Power Plant. For the fiscal year ended December 31, 2016, the City paid $11,237,160 under this contract. In 2017, such payments are estimated to total $5,927,812.

Debt Service Coverage

[Currently under review by the Utilities] The ordinances governing the Parity Bonds include a rate covenant requiring that rates charged to users of the System's services be sufficient so that the ratio of Net Pledged Revenues to debt service on the Parity Bonds for the current fiscal year will be at least 1.30 (the "Rate Coverage Ratio"). Historically, the City has maintained debt service coverage greater than the required Rate Coverage Ratio of 1.30.

A separate debt service coverage covenant in the Bond Ordinance, applicable to the Utilities' issuance of additional bonds in certain situations, requires the ratio of Net Pledged Revenues to Average Annual Principal and Interest Requirements to be at least 1.30 (the "Additional Bonds Coverage Ratio").

The table on the following page shows debt service coverage as calculated by the Utilities with respect to the years indicated (without taking into account component units) using the Average Annual Principal and Interest Requirements as of each year (as required for the Additional Bonds Coverage Ratio) and using the fiscal year debt service for each year (as required for the Rate Coverage Ratio):

Debt Service Coverage

	Fiscal Year Ended December 31				
	2012	***2013***	***2014***	***2015***	***2016***
Operating Revenues	$ 849,746,643	$ 823,759,529	$ 868,847,747	$ 830,820,813	$ 793,292,942
Operating Expense	(674,479,711)	(667,268,714)	(686,762,702)	(613,716,169)	(625,442,918)
Depreciation and Amortization	$ 116,184,836	$ 118,430,128	$ 119,842,074	$ 120,099,931	$ 129,693,856
Operating Revenues Available For Debt Service	$ 291,451,768	$ 274,920,943	$ 301,927,119	$ 337,204,575	$ 297,543,880
Interest Earnings (excl. interest on bonds)(1)	11,006,444	8,431,662	8,423,858	8,604,113	9,068,244
Development Fees(2)	35,343,372	30,766,658	29,194,146	28,654,702	35,465,693
Net Pledged Revenues	$ 337,801,584	$ 314,119,263	$ 339,545,123	$ 374,463,390	$ 342,077,817
Average Annual Principal and Interest Requirements	$ 104,436,237	$ 112,483,565	$ 112,667,232	$ 110,700,469	$ 108,666,374
Additional Bonds Coverage Ratio	3.23	2.79	3.01	3.38	3.15
Fiscal Year Debt Service	$ 151,142,496	$ 154,192,910	$ 162,598,321	$ 167,284,812	$ 175,109,056
Rate Coverage Ratio(3)	2.23	2.04	2.09	2.24	1.95

(1) Interest Earnings include Build America Bond cash payment subsidies received; 2012 - $8,550,623; 2013 - $7,870,848; 2014 - $7,930,703; 2015 - $7,947,804 and 2016 - $7,964,905.

(2) Development Fees are cash contributions for general and specific utilities capital projects. These fees are utilized to compensate existing customers for the costs of developing the System and to help pay for the growth of the System caused by new customers.

(3) The determination of the Rate Coverage Ratio calculation was revised to include moneys previously accumulated by the Utilities to make principal and interest payments on outstanding bonds that were subsequently refunded. These moneys were then transferred to escrow funds to cover principal and interest payments on refunded bonds. The amounts added to Fiscal Year Debt Service for 2012 - $7,919,848; 2013 - $0; 2014 - $0; 2015 - $0 and 2016 - $0.

[Currently under review by the Utilities] The Utilities' goal is a Rate Coverage Ratio of 2.0 or greater, after accounting for surplus payments to the City. However, actual coverage ratios will be a function of not only the Utilities' long term capital structure but also the specific costs and revenues in each year. This can be significantly impacted by economic conditions, annual weather variations, volatility in fuel and power markets, and other factors.

Debt Service Schedule

The following table sets forth the estimated debt service schedule for the Bonds and the outstanding Parity Bonds. This table does not reflect the refunding of the Refunded Obligations. See APPENDIX G – THE REFUNDING PLAN.

Year	Debt Service on Outstanding Parity Bonds (1) (2)	Series 2017A-1 Bonds Principal(1)(3)	Series 2017A-1 Bonds Interest	Series 2017A -2 Bonds Principal(1)(3)	Series 2017A -2 Bonds Interest	Series 2017A -3 Bonds Principal(1)(3)	Series 2017A -3 Bonds Interest	Total Debt Service Requirements
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
2032								
2033								
2034								
2035								
2036								
2037								
2038								
2039								
2040								
2041								
2042								
2043								
2044								
2045								
2046								
2047								
2048								
2049								
2050								

(1) Exclusive of costs associated with Support Facilities.
(2) Includes principal, interest and mandatory sinking fund payments with respect to the Parity Bonds, excluding the Bonds. Interest does not reflect subsidy expected to be received on outstanding Build America Bonds. This assumes an interest rate of 4.90% for the variable rate 2002C Bonds and an interest rate of 3.00% for the unhedged portion of the 2009C Bonds. This also assumes 4.112% for the 2004A Bonds, an interest rate of 4.7099% for the 2005A Bonds, an interest rate of 4.4810% for the 2006A Bonds, an interest rate of 3.198% for the 2007A Bonds, an interest rate of 5.295% for the 2007B Bonds, an interest rate of 4.2686% for the 2008A Bonds, an interest rate of 3.8807% for the 2010C Bonds, and an interest rate of 4.0242% for the 2012A Bonds based upon swap agreements related to these bonds. Assumes an interest rate of 5.475% for $61,475,000 of the 2009C Bonds based upon the swap agreement related to that portion of the 2009C Bonds. See "—Interest Rate Swap Agreements" above.
(3) Includes principal and mandatory sinking fund payments with respect to the Bonds.
Source: George K. Baum & Company, as Financial Advisor.

Financial Risk Management Policy

The Utilities has adopted a Financial Risk Management Policy as part of a broader Enterprise Risk Management Policy. The stated goals of the Financial Risk Management Policy are to minimize debt cost, maintain quality credit ratings, balance risk and benefits, and maintain financial flexibility. The primary features of the Financial Risk Management Policy are discussed below.

Risk Management Committee. As part of an enterprise wide risk management initiative, Utilities has formed a Risk Management Committee which reports to the Chief Executive Officer. The committee, along with the Chief Executive Officer, is responsible for the overall direction, structure, conduct, control, and reporting of the Utilities' risk management activities. The committee's voting members consist of the officers (except for the Chief Executive Officer) of the Utilities.

[1] Preliminary, subject to change

Variable Rate Debt. Pursuant to the Utilities' Financial Risk Management Policy, the Utilities is allowed to have up to 30% of its total outstanding debt in unhedged variable rate debt. Currently, the Utilities has __% of its total outstanding debt including Commercial Paper in a variable rate structure which is not hedged. This percentage does not reflect the refunding of the Refunded Obligations. This percentage does not include the Utilities' bonds that are hedged with a variable to fixed interest rate swap transaction. These bonds include the outstanding Variable Rate Demand Utilities System Subordinate Lien Refunding Revenue Bonds, Series 2004A, Variable Rate Demand Utilities System Subordinate Lien Improvement Revenue Bonds, Series 2005A, Variable Rate Demand Utilities System Subordinate Lien Improvement and Refunding Revenue Bonds, Series 2006A, Variable Rate Demand Utilities System Subordinate Lien Improvement Revenue Bonds, Series 2006B, Variable Rate Demand Utilities System Improvement Revenue Bonds, Series 2007A, Variable Rate Demand Utilities System Improvement and Refunding Revenue Bonds, Series 2007B, Variable Rate Demand Utilities System Improvement Revenue Bonds, Series 2008A, a portion of Variable Rate Demand Utilities System Refunding Revenue Bonds, Series 2009C, Variable Rate Demand Utilities System Improvement Revenue Bonds, Series 2010C, and the Variable Rate Demand Utilities System Improvement Revenue Bonds, Series 2012A.

Currently, the Utilities has __% of its total outstanding debt in a variable rate structure which is hedged.

Credit Risk. Pursuant to the Utilities' Financial Risk Management Policy, all counterparties in swap or other financial products agreements with the Utilities must have a long-term credit rating in the "A-" category issued by at least one major credit rating agency at the time of execution of such swap or financial products agreement, though there is no requirement that such a rating be maintained throughout the life of the financial products agreement. In the alternative, a counterparty must provide a guarantee, swap surety, or other form of credit enhancement such that its enhanced creditworthiness is in at least the "A-" category at the time of execution of such swap or financial products agreement.

Capital Improvements

The 2017 Annual Budget approved by City Council on November 22, 2016 included total capital expenditures of approximately $200.4 million. This is approximately $17.7 million less than the budgeted amount for 2016. Electric projects account for 41.2% of the total major capital projects budget. Combined water and wastewater projects account for 43.3% of the total.

Some of the major projects included as a part of the Utilities' capital improvement program are described under "THE ELECTRIC SYSTEM – Environmental Regulation," "THE WATER SYSTEM – Capital Improvements to the Water System," and "THE WASTEWATER SYSTEM – Capital Improvements to the Wastewater System." Capital expenditures are currently budgeted to total approximately $___ billion through [2020]. The Utilities' forecasts of its long range capital expenditures and the timing of construction of a number of the proposed major capital projects are dependent on future economic conditions, population growth within the Utilities' service areas and other factors beyond its control, such as environmental regulations. The ability of the Utilities to construct these projects in the projected timeframes and to maintain the Rate Coverage Ratio at historical levels will depend, in part, upon rate increases in future years.

Tax and Spending Limits

In 1991, the City's voters approved an amendment to the Charter (the "Charter Amendment"), and in 1992, the State's voters approved an amendment to the Colorado Constitution (the "Constitutional Amendment" and together with the Charter Amendment, the "Amendments"). The Amendments are similar and attempt to restrict the City's spending by (a) limiting the amount by which fiscal year spending may change from year to year in accordance with a formula based upon inflation and City growth, (b) limiting annual changes in City property taxes in accordance with a formula based upon inflation and City growth and (c) requiring voter approval in advance for new taxes, tax rate increases, certain property tax mill levies and the creation of most direct or indirect City obligations. While several provisions of the Amendments have been interpreted by the courts, many provisions remain unclear and may require judicial interpretation in the future.

Both Amendments, however, exclude "enterprises," which are defined as government-owned-business authorized to issue revenue bonds and receiving under 10% of annual revenue in grants from all state and local governments combined. Management of the Utilities believes that the Utilities currently constitutes an "enterprise" under the Amendments due to the level of revenues it currently receives from governmental grants. Management of the Utilities also considers it extremely unlikely that in the future the Utilities would receive a sufficient percentage of its revenues from government grants to cause the Utilities to lose its status as an "enterprise" for purposes of the Amendments.

If the Utilities ever ceases to be an enterprise within the meaning of either of the Amendments, the Utilities' spending and revenues would become integrated with the City's overall spending and revenues for purposes of compliance with the applicable Amendment. In such a situation, the applicability of the spending and revenue limitations upon the Utilities could restrict the Utilities' ability to spend the Utilities' revenues in excess of such limitations absent voter approval. The effect of any future inclusion of the Utilities as part of the City's compliance with the limitations of the Amendments would depend on the City's overall spending and revenues at that time. Furthermore, the provisions of the Amendments requiring voter approval for City obligations would apply to future bond issues of the Utilities, including certain refunding bonds, and the Constitutional Amendment's 3% reserve requirement would become applicable to the City, which would then include the Utilities as part of the City. Even if the Utilities ceases to have enterprise status within the meaning of either of the Amendments, however: (i) the City could still impose increased fees, rates and charges for the Utilities without voter approval; (ii) the rate covenant and the lien on Net Pledged Revenues provided for in the Bond Ordinance will continue to secure the payment of debt service on the Bonds; and (iii) if the City is required to reduce spending in order to comply with its overall spending limit, the City would first be required to reduce spending for purposes for which it does not have an obligation under law or by contract prior to reducing spending required to comply with its covenants related to outstanding indebtedness (including the debt of the Utilities).

The City and the Utilities have not conducted a detailed analysis, however, of the overall impact on the City and the Utilities if the Utilities ever ceases to qualify as an "enterprise;" accordingly, no representation can be made as to the overall impact of the Amendments on the future activities of the Utilities.

Insurance

The Utilities' Enterprise Risk Management group is responsible for developing the process to identify, prioritize, and report risks so that appropriate mitigation plans are developed and implemented to protect and enhance the business performance of the Utilities. The program requires specific risk mitigation policies, plans and procedures be maintained to identify significant risks, document risk mitigation plans, and ongoing monitoring and communication.

As part of this broader enterprise risk process, the Utilities manages an ongoing insurance risk management program, insuring against both hazard and liability exposures where appropriate. Working with insurance providers and the Utilities' operations, loss tolerances are identified and insured through the provider, or are self-insured.

The Utilities has insurance policies covering damages due to most types of major losses. Property insurance for physical damage is purchased commercially for the Utilities' facilities and for most of the infrastructure (excepting transmission lines, underground piping, and dams). Coverage for losses under the Terrorism Risk Insurance Act is purchased under the property insurance. The Utilities also purchases comprehensive information security and privacy "cyber" liability insurance, with a retention level of $1,000,000 per occurrence.

The Utilities is covered under the Colorado Governmental Immunity Act for certain liability claims. The Colorado Governmental Immunity Act provides the maximum amount that may be recovered through tort claims under Colorado law of $350,000 for any injury to one person in any single occurrence and $990,000 for any injury to two or more persons in any single occurrence. To cover auto and general liability exposures not covered by the Colorado Governmental Immunity Act, the Utilities purchases excess liability coverage, with a retention level of $1,000,000 per occurrence.

The Utilities accrues on its Statements of Net Position as a liability an amount estimated for public officials', general and auto liability claims. As of December 31, 2016, the Utilities' Statements of Net Position reflected an accrual of $3,066,242.

Workers' compensation claims are self-insured and managed by City in-house staff. An excess workers' compensation liability insurance policy is purchased for statutory benefits in excess of $750,000 per occurrence. The Utilities also contributes, along with the City, to a joint Workers' Compensation Self-Insurance Fund. The Utilities' outstanding workers' compensation claims are reserved at $1,362,026 as of December 31, 2016, under the City's self-insurance fund. The City believes that any liability arising out of unforeseen losses will not materially impact Utilities' financial position. This balance is not reflected on Utilities' Statements of Net Position.

Infrastructure Security

The Utilities is committed to ensuring reliability of service through the protection of its critical infrastructure and by providing a secure environment for employees and customers. Federal directives and mandates such as the North American Electric Reliability Corporation Critical Infrastructure Protection Standards, Department of Homeland Security Chemical Facility Anti-Terrorism Standards, Department of Homeland Security Critical Infrastructure Protection Program, and Fair and Accurate Credit Transactions Act require the development, implementation, and ongoing administration of security programs and plans to protect critical infrastructure, cyber assets and customer information. In addition, the Utilities Governance Policy requires that programs be in place to protect corporate assets including, but not limited to, physical assets, intangible assets, intellectual property, confidential customer information and records. Finally, the Utilities' commitment to the corporate values around "people" and "safety" ensures through its practices that employees and customers conduct business in a safe and secure environment.

Actions taken as a result of federal and state mandates, risk and vulnerability assessments, and the Utilities Governance Policy include security hardening, the addition and placement of security personnel to protect critical utilities infrastructure and cyber assets, an identity theft prevention program to protect customer information, and enhanced information technology vulnerability assessments, controls and training to mitigate the risk of compromising systems and business information. Overall, the Utilities' approach to security is one of balancing cyber security technology with a physical security control and response.

Emergency Management and Business Continuity programs for the Utilities centers on a new business model which integrates the practices and principles of emergency operations and continuity of operations planning. These programs target an enhanced enterprise-wide state of readiness which embodies crisis management preparedness for the four utility services as well as support departments. Initiatives associated with this new model include a comprehensive risk assessment approach which involves a joint Threat and Hazard Vulnerability Analyses and enhanced Business Impact Analysis model; the consolidation of approximately 40 disparate emergency/continuity plans into a single Emergency Operations Plan hierarchy with functional and/or risk specific subordinate Emergency Continuity Plans; the creation of a formal Crisis Management Team; Utility focused Crisis Management Team – Incident Command System 300 Level training for all Crisis Management Team personnel; and the development of a series of Crisis Management Team tabletop and functional exercises. Dam emergency planning is also being enhanced to include outreach and orientations to emergency managers and public safety personnel in communities where the Utilities' dams pose a risk.

Investment Policy

Pursuant to a City Council resolution, the Chief Executive Officer implemented the "Colorado Springs Utilities Investment Policy" (the "Investment Policy"). The most recent revision to the Investment Policy is dated February 28, 2017. The principal objectives of the Investment Policy are: (a) the preservation of capital and protection of investment principal; (b) maintenance of sufficient liquidity to meet anticipated cash flows; (c) diversification to avoid unreasonable market risk; (d) attainment of a market rate of return; (e) conformance with all City, state and federal regulations; and (f) conformance with all applicable bond ordinance provisions for the outstanding utilities revenue bonds. Consistent with the Utilities' Financial Risk Management Policy, at the time of selection, only financial institutions and banks with a minimum credit rating (long-term) in the "A-" category by at least one of the three major credit rating agencies (Moody's, Standard and Poor's and Fitch) shall be eligible to provide safekeeping and custodial services to the Utilities. In the absence of this minimum rating requirement, financial institutions and banks may also provide a guarantee, swap surety or other form of enhancement to get to the "A-" category at the time of execution. All banks must be members of the FDIC.

THE ELECTRIC SYSTEM

The Electric System provides retail service to metropolitan Colorado Springs, Manitou Springs, and portions of the City of Fountain, and delivers special contract power to the Academy, Peterson and Fort Carson. More than 90% of the population of El Paso County (the "County") is directly or indirectly served by the Electric System.

The Utilities has the electric franchise to serve Manitou Springs through July 2024. As part of its agreement with Manitou Springs, the Utilities must pay Manitou Springs a franchise fee equal to 8% of the gross revenues from the electric service provided to customers within the municipal limits of Manitou Springs. Such franchise fee may be payable in cash or in-kind services; provided that the cash element of the franchise fee payment may not be less than 2% of the gross revenues received from the electric service for any month during the franchise.

The Utilities also has the electric franchise to serve portions of the City of Fountain through December 2033. As part of its agreements with the City of Fountain, the Utilities will not pay a franchise fee for electric service within the current service area of City of Fountain.

Electric Rates

In addition to base electric rates, the Utilities charges customers an electric cost adjustment, which reflects the changes in the average costs of purchased power and unit fuel costs. The electric cost adjustment may be changed as frequently as monthly to reflect actual costs of fuel and purchased power to customers on a timely basis.

The following base rates for residential and small commercial service have been in effect since April 1, 2017.

Electric Rates
(As of July 1, 2017)

	Standard Option:	
Residential Service		
Electric Cost Adjustment[1]	Per kWh	$ 0.0195
Electric Capacity Charge	Per kWh	0.0014
Access and Facilities Charges	Per day	0.5010
	Per kWh	0.0763
Commercial Service General		
Electric Cost Adjustment[1]	Per kWh	0.0195
Electric Capacity Charge	Per kWh	0.0012
Access and Facilities Charges	Per day	0.7416
	Per kWh	0.0618

(1) The Utilities' electric rates include an electric cost adjustment, which reflects changes in the cost of fuel and purchased power. The current electric cost adjustment was effective May 1, 2017 and can change monthly

The City Council is authorized to determine rates charged for electric services within the Electric System's total service area (both inside and outside City limits). However, if the rates to be charged for the same customer classifications are different for customers within and outside the City limits, then a state statute requires that rates to be charged outside the City limits be reviewed and approved by the Colorado Public Utilities Commission (the "PUC") before becoming effective. The statute also provides that the PUC has jurisdiction to resolve any conflict relating to the rates established by the City Council upon the filing of a complaint by 5% of the affected customers outside the City limits (which, in the case of the Electric System's residential customers, would be approximately 868 customers). Under the statute, the City Council is ordinarily required to give at least 30 days' notice prior to holding a public hearing to consider proposed base rate changes. The statute allows rate changes absent the public notice and hearing for good cause. By virtue of the ordinances establishing the rate making process for the Utilities, a 30 day public notice is not provided for changes to the electric cost adjustment. Published notice is provided within 10 days after City Council approval for the electric cost adjustment.

Electric System Sales and Revenues

The ten largest customers of the Electric System during 2016, ranked by sales volume in megawatt hours ("MWh"), represented 720,242 MWh, or 16.2% of sales (excluding interdepartmental and miscellaneous sales), and $38.1 million or 9.5% of revenues during that period (excluding interdepartmental revenues, wheeling and miscellaneous revenues previously classified as non-regulated revenues).

Four of the Electric System's military customers, Peterson, the Academy, Cheyenne Mountain Air Force Station and Fort Carson, purchase a portion of their power from WAPA. The Utilities imposes wheeling rates for WAPA power delivered over the Electric System's facilities to these customers, and such wheeling rates and backup power charges are designed to recover the Electric System's costs of service.

The number of active residential meters served by the Electric System was 184,135, 187,339, 190,382, and 191,539 at the end of 2013, 2014, 2015, and 2016 respectively. The average annual use per residential customer was 7,910 kilowatt hours in 2013, 7,562 in 2014, 7,662 in 2015, and 7,770 in 2016.

The following tables set forth Electric System sales and revenues by customer class for the past five years:

Customer Class	*Electric Sales (MWh) Fiscal Year Ended December 31*				
	2012	***2013***	***2014***	***2015***	***2016***
Residential	1,471,135	1,456,492	1,416,750	1,458,677	1,488,251
Commercial / Industrial-Small	679,095	715,267	719,057	729,711	733,576
Commercial / Industrial-Large	1,861,948	1,858,543	1,851,967	1,859,780	1,875,393
Special Contract Service	371,603	335,555	272,284	335,498	342,964
Street Lighting	1,462	1,480	1,453	505	2,662
Traffic Signals	1,784	1,793	1,832	1,855	1,853
Subtotal	4,387,027	4,369,131	4,263,343	4,386,026	4,444,699
Interdepartmental	164,867	129,642	100,774	98,486	108,092
Miscellaneous Sales(1)	221,610	598,406	494,752	566,511	423,839
Total Electric Sales	4,773,504	5,097,180	4,858,869	5,051,023	4,976,630
Less Interdepartmental Sales	(164,867)	(129,642)	(100,774)	(98,486)	(108,092)
Net Electric Sales	4,608,637	4,967,537	4,758,095	4,952,537	4,868,538
Wheeled Power(1)	31,020	31,902	32,902	32,799	32,819
Net Peak Demand (MW)	908	878	879	851	890
Total Number of Active Electric Meters as of Year End	214,600	217,273	220,568	223,109	225,406

(1) 2012 was restated removing Wheeled Power from Miscellaneous Sales and placing it below the Net Electric Sales line.

Customer Class	*Electric Revenues Fiscal Year Ended December 31*				
	2012	***2013***	***2014***	***2015***	***2016***
Residential	$167,424,003	$162,929,577	$170,971,153	$180,009,198	$180,070,392
Commercial / Industrial – Small	60,276,603	62,696,849	66,404,010	66,700,175	64,309,468
Commercial / Industrial – Large	135,097,157	127,962,945	141,000,645	140,062,871	133,316,127
Special Contract Service	22,654,448	20,012,738	18,624,567	19,541,288	18,310,028
Street Lighting	4,211,152	4,544,770	4,398,201	4,173,593	4,368,032
Traffic Signals	264,629	262,895	275,187	275,372	274,505
Subtotal	$389,927,992	$378,409,774	$401,673,763	$410,762,497	$400,648,552
Interdepartmental	12,905,291	9,045,857	8,196,802	8,430,516	8,453,678
Subtotal	$402,833,283	$387,455,631	$409,870,565	$419,193,013	$409,102,230
Miscellaneous Revenue(1)	18,411,373	34,292,730	27,337,918	25,897,720	17,030,047
Total Electric Revenue	$421,244,656	$421,748,360	$437,208,483	$445,090,733	$426,132,277
Less: Interdepartmental Sales	(12,905,291)	(9,045,857)	(8,196,802)	(8,430,516)	(8,453,678)
Net Electric Revenue	$408,339,365	$412,702,504	$429,011,681	$436,660,217	$417,678,599
Wheeled Power(1)	$ 281,570	$ 281,099	$ 281,099	$ 281,099	$ 281,570

(1) 2012 was restated removing Wheeled Power from Miscellaneous Revenue and placing it below the Net Electric Revenue line.

System Capability

The Electric System peak (net of auxiliary power used to operate the generating units) of 908 megawatts ("MW") was established in July 2012. The following table sets forth information on the sources and amount of the net capability of the Electric System. Currently, the Electric System's non-coal fired units are used primarily for intermediate, peaking and standby service.

Net Capability of Electric System

Unit	*Fuel*	*Year Unit Completed*	*2016-2017 Net Winter Capability (MW)*[1]	*2017 Net Summer Capability (MW)*
Owned Assets:				
Drake #5[2]	Coal or Gas	1962	46	0
Drake #6	Coal or Gas	1968	77	77
Drake #7	Coal or Gas	1974	131	131
Birdsall #1	Gas or Oil	1953	16	16
Birdsall #2	Gas or Oil	1954	16	16
Birdsall #3	Gas or Oil	1957	23	23
Nixon #1	Coal	1980	208	208
Nixon #2 & 3 (Combustion Turbines)	Gas	1999	64	60
Front Range Power Plant	Gas	2003	480	460
Cascade, Tesla, Manitou, and Ruxton	Hydro		35	35
Total Resources			1,096	1,026
Purchases:				
U.S. Department of Energy, Western Area Power Administrative Purchase:				
Salt Lake City Integrated Projects			60	15
Loveland Area Projects			57	61
Wind Purchases			2	0
United States Air Force Academy Solar			5	5
Solar Gardens			4	4
Clear Springs Ranch Solar Array			10	10
Total Purchases			138	95
Grand Total			1,234	1,121

(1) "MW" is an abbreviation for megawatt.
(2) On December 31, 2016 Martin Drake Unit 5 was moved from inactive reserve status to a retired status. The 46 Net MW capacity of the unit is no longer available to System Operations.

The table below details the Utilities' potential summer resources classified by energy source. The Utilities' actual energy output from these resources can, and frequently does, significantly differ from the percentages shown below.

Potential Summer 2017 Resources

	Resources (MW)	*Pct.*	*Purchases (MW)*	*Pct.*	*Total (MW)*	*Pct.*
Coal	416	41%	0	0%	416	37%
Natural Gas and Oil	575	56%	0	0%	575	51%
Hydro Generation	35	3%	76	80%	111	10%
Other Renewable Resources	0	0%	19	20%	19	2%
Total	1,026	100%	95	100%	1,121	100%

In 1989, the Utilities entered into contracts with WAPA for post September 30, 1989 energy and capacity. These contracts were later extended to September 30, 2024. The Loveland Area Projects contract is now extended from 2024 through 2054. The two WAPA contracts are for purchases from WAPA's Salt Lake City Integrated Area Projects ("SLCA/IP") and from its Loveland Area Projects ("LAP"), providing for 15.1 MW in the summer season and 60.3 MW in the winter season, and 60.7 MW in the summer season and 57.6 MW in the winter season, respectively.

Currently, the energy available under the SLCA/IP contract is controlled by the Record of Decision on the Glen Canyon Environmental Impact Statement (the "EIS"), which was implemented on April 1, 1997. Because of the EIS and the resulting Glen Canyon operating criteria, generation at SLCA/IP facilities has been reduced. As a result, WAPA determines monthly Available Hydro Power ("AHP") based on prevailing water release conditions. To the extent that AHP does not meet WAPA's firm obligations, WAPA has made arrangements to purchase Western Replacement Power ("WRP") for its customers up to an amount not to exceed their firm allocations. The cost of WRP is on a pass-through-cost basis. The Utilities takes advantage of WRP as needed.

The LAP contract also provides the option for 3.9 kilowatt-hours per kilowatt of its contract capacity for summer season and 4.4 kilowatt-hours per kilowatt of its contract capacity for the winter season, to be provided from WAPA's Mount Elbert pumped storage facility. Any energy taken from this account must be returned to the Mount Elbert plant at the rate of 1.4 megawatt hours returned for each megawatt hour received to meet the pumping requirements.

The Utilities reviews its Electric Integrated Resource Plan (the "EIRP") annually, and officially submits an update to WAPA every five years. New resources, including renewable energy, are evaluated as well as demand side management strategies.

Fuel Supply

The Utilities' coal and smaller hydro units are normally operated as base-load facilities, while its natural gas and large hydro units are utilized for shaping supply to follow changing and peaking loads. The 2010 purchase of the Front Range Power Plant, a 480 MW natural gas fired combined cycle electric generation facility located south of the City, significantly increased the percentage of electricity generated using natural gas as a fuel. Also, when necessary or economical, the Utilities will purchase market power to supplement existing generation resources.

The Utilities has about 1.2 billion cubic feet of gas storage capacity under the Cheyenne Market Center storage service provided by Tallgrass Interstate Gas Transmission. Storage services are renegotiated periodically with various providers, but the level of capacity is consistent. The primary use of the storage service is to provide firm deliveries and balancing of gas supplies to the Utilities' Front Range Power Plant and nearby Nixon gas turbines. The Utilities also maintains firm natural gas pipeline transportation from various Rocky Mountain supply areas sufficient to meet fuel requirements. This includes about 95,000 MMBTU/D to the Front Range Power Plant and 10,000 MMBTU/D to two gas fired turbines located near the Nixon coal plant. During the summer months, the gas utility releases 18,000 MMBTU/D of their surplus gas pipeline capacity to the electric utility for use by the gas fired turbines at Nixon during the peak season.

When natural gas prices are low, gas generation throughout the U.S. can be more economical than coal, leading to significant reduction in both coal production and prices. Arch Coal and Peabody Energy, two of the top coal producers in the world, are emerging from Chapter 11 bankruptcy protection in 2017. These companies own and operate the two largest mines in the southern Powder River Basin in Wyoming, Black Thunder mine (Arch) and North–Antelope Rochelle mine (Peabody), which are the sources for the majority of coal used by Utilities. Utilities continues to maintain a good working relationship with these mines and the mines themselves continue to supply all the coal utilities has sought to purchase from them.

The Utilities' coal supplies and transportation services are procured through a portfolio of contracts which are managed to ensure a dependable and economic fuel supply. Nearly all of the Utilities' coal supply is from the southern Powder River Basin in Wyoming. Approximately 50% of future coal demand is purchased under a term contract. Spot market contracts with terms varying between one month and one year supply the remaining 50%. This contractual flexibility allows Utilities to respond quickly to changes in plant operations and market conditions. Coal inventory levels as of December 31, 2016, were at or above Utilities' target ranges.

Colorado Renewable Energy Standard

In November 2004, Colorado voters approved an initiative that created a renewable portfolio standard for retail electric utilities in Colorado that serve over 40,000 customers, such as the Utilities (each a "qualifying utility"). The language of that initiative was modified by the Colorado General Assembly and codified in C.R.S. Section 40-2-124. The statute was subsequently amended by the Colorado General Assembly in 2007, 2008, 2010, and 2013 and was renamed the Colorado Renewable Energy Standard. The Colorado Renewable Energy Standard requires qualifying utilities to acquire a defined percentage of their electricity from "eligible energy resources," which include solar, wind, geothermal, qualifying biomass, coal mine methane, synthetic gas produced by pyrolysis of municipal solid waste, existing hydroelectric generation with a nameplate rating of 30 megawatts or less, and new hydroelectric generation with a nameplate rating of 10 megawatts or less.

The PUC has established a system under which a qualifying utility with extra eligible energy in the form of a "Renewable Energy Certificate" may sell its extra Renewable Energy Certificates to other qualifying utilities in need of additional renewable energy to satisfy the Colorado Renewable Energy Standard requirements.

The statute requires the PUC to establish a maximum retail rate impact for compliance with the Colorado Renewable Energy Standard requirements of 2% of the total electric bill annually for each customer of a cooperative electric association and investor-owned utility that is a qualifying utility. The Utilities filed its self-certification statement with the PUC on September 7, 2006 which set its maximum retail rate impact at 1%. If a qualifying utility reaches the rate cap but is otherwise unable to meet the Colorado Renewable Energy Standard requirements, then it is exempt from administrative penalties for such noncompliance.

The final version of Colorado Renewable Energy Standard does not apply to the Utilities, but the Utilities has chosen to exceed the Colorado Renewable Energy Standard requirements for renewable energy resources, which are 3% of Colorado retail sales for the years 2011 through 2014, 6% for the years 2015 through 2019, and 10% for the year 2020 and thereafter.

Based on expected load projections made in 2016, the Utilities expects to have sufficient eligible energy resources to comply with the Colorado Renewable Energy Standard requirements through at least 2028. During 2006-2010, the Utilities made a substantial purchase of "Renewable Energy Certificates," to be received in future years, which will be used along with qualifying generation hours from the Utilities-owned generation units to comply with the Colorado Renewable Energy Standard. WAPA successfully qualified its hydroelectricity units under 30 megawatts as qualifying renewable energy generating resources in the State of Colorado and will deliver the Renewable Energy Certificates to the Utilities as part of two WAPA power purchase agreements. The Renewable Energy Certificates from the WAPA power purchase agreements will be used by the Utilities for Colorado Renewable Energy Standard compliance. In 2015 the Utilities entered into additional local Renewable Energy Certificate purchase agreements and a new Purchase Power Agreement with associated Renewable Energy Certificates through a solar array located on Utilities property to ensure compliance with the Colorado Renewable Energy Standard.

To comply with the Colorado Renewable Energy Standard after 2028, and to meet voluntary renewable energy goals in excess of the Colorado Renewable Energy Standard requirements, the Utilities is considering the acquisition of additional eligible energy resources. The Utilities updated its Electric Integrated Resource Plan in 2015. The updated Electric Integrated Resource Plan identifies potential new renewable energy resources.

Transmission and Distribution Facilities and Interconnections

The Electric System's transmission system is interconnected with WAPA at the Midway substation south of the Nixon Plant and with Xcel Energy at the Fuller substation and Flying Horse substation in the northeast part of the City.

The Utilities is a member of a group of power suppliers operating in Colorado, Wyoming, Nebraska and South Dakota known as the Rocky Mountain Reserve Group. The participants pool their reserve capacities and provide mutual assistance in times of emergency. Participants must maintain reserve capacity based on their loads and their largest hazard as a ratio of the pool load and the largest generating unit within the pool.

[Discussion of possible RTO to come.]

Decommissioning of Martin Drake Power Plant

In November 2015, the Utilities Board voted to close and decommission the Martin Drake power plant no later than 2035. On December 31, 2016 Unit 5 was moved from inactive reserve status to a retired status. The 46 Net MW capacity of the unit will no longer be available to system operations. The timing of closing and decommissioning (other than the 2035 date) units numbers 6 and 7 has not been determined. The Utilities is continuing to evaluate the transmission, generation, and fuel infrastructure that could be needed to decommission and replace the plant prior to 2035.

Environmental Regulation

In operating the Electric System, the Utilities is subject to various State and federal environmental requirements, which affect operating and capital costs of the System. Ongoing promulgation of new regulations under the Clean Air Act Amendments of 1990 and the Colorado Air Quality Control Act will have the effect of imposing more stringent air emission requirements for the Electric System's generating facilities, particularly the Nixon and Drake coal-fired units.

The Federal Clean Air Act requires that states develop "State Implementation Plans" ("SIPs") that address how each state will control air pollution, including visibility impacts to Class I federal areas. The EPA's Regional Haze Rule requires that certain emission sources, such as Drake, that may reasonably be anticipated to cause or contribute to visibility impairment in Class I areas, to install Best Available Retrofit Technology ("BART"). Additionally, Colorado's Regional Haze SIP phases in emission limits for other stationary sources, such as Nixon, as part of "Reasonable Progress" towards natural levels of visibility under the Regional Haze Rule. The Regional Haze Rules requirements for Drake and Nixon were approved by the State legislature in May 2011. The EPA approval of the SIP had an effective date of January 30, 2013. The Utilities submitted its required proposed Compliance Schedule to the Air Pollution Control Division of the Colorado Department of Public Health and Environment ("CDPHE") on March 28, 2013. On November 4, 2013 the Utilities was notified by the Air Pollution Control Division that the compliance schedule proposed by the Utilities was approved. In December, 2014 the Utilities submitted a proposed revision to the compliance schedule to the Air Pollution Control Division and received notice of approval for the revised compliance schedule on March 16, 2015.

The Utilities is currently implementing its approved BART and Reasonable Progress plans. The BART emission limits for nitrogen oxides ("NOx") for Drake were met by the installation of over fire air and ultra-low NOx burners on Drake units 6 and 7 in 2014. The BART emission limits for sulfur dioxide ("SO2") for Drake will be met by scrubbers for units 6 and 7 and the projects to install these controls are currently underway. Because Drake unit 5 will be decommissioned prior to the compliance date, there will be no additional investment in pollution controls for this unit. As of March 31, 2017, there are no remaining capital costs for the Drake unit 6 and 7 scrubbers. Drake units 6 and 7 must achieve compliance with the SO2 emission limits no later than December 31, 2017. The Reasonable Progress emission limits for NOx for Nixon unit 1 will be met by the installation of over fire air and ultra-low NOx burners and the Reasonable Progress emission limits for SO2 will be met by the installation of a scrubber. The Nixon scrubber project began in late 2013, and the Nixon NOx project began in 2015. As of March 31, 2017 the estimated remaining cost of these controls is $22 million. Nixon unit 1 must achieve compliance with the emission limits by December 31, 2017.

For particulate matter control, both Nixon and Drake have been equipped with fabric filter baghouses. Currently these baghouses achieve a removal efficiency of greater than 95%. Through its BART and Reasonable Progress analysis of Drake and Nixon, the State has determined that the existing baghouses represent the most stringent controls for particulate matter and will be sufficient to meet BART and Reasonable Progress limits. Drake and Nixon certified compliance with BART and Reasonable Progress particulate emission limits in May 2013.

Drake Units 6 and 7 (all coal-fired), Nixon Units 1 (coal-fired), 2 and 3 (both natural gas-fired), and Front Range Power Plant Units 1 and 2 (both natural gas-fired) are subject to the Clean Air Act Title IV Phase 2 Acid Rain Requirements. The Utilities has sufficient emission allowances to satisfy its future SO2 allowance obligations.

As an ongoing regulatory process to implement its 2010 revised SO2 National Ambient Air Quality Standard, EPA requested that Colorado submit a designation for Drake as being “attainment area,” “nonattainment area,” or “unclassifiable.” In August 2015, the Colorado Air Quality Control Commission approved the designation of Drake as “unclassifiable” for submission to the EPA. The EPA accepted this recommendation in September, 2016. The ongoing regulatory process at the State level for an attainment or nonattainment status for Drake will continue into 2017. On March 16, 2017, the Colorado Air Quality Control Commission accepted the Colorado Air Quality Control Division’s designation for Nixon as “attainment/unclassifiable” for submission to the EPA.

Additional regulations, such as the October 1, 2015 EPA release of the final revised National Ambient Air Quality Standard for ozone, which lowered the standard from 75 parts per billion to 70 parts per billion, may necessitate the installation of additional pollution controls beyond those described above. While it is uncertain the extent to which these regulations, particularly the lowering of the ozone standard, will affect the Utilities’ power plants or operations, additional future pollution controls for NOx, i.e., post-combustion controls such as Selective Catalytic Reduction, could potentially cost the Utilities an additional $151 million beyond 2020, depending on which units would be required to install such controls.

In December 2011, the EPA’s final Maximum Achievable Control Technology rule was finalized as the Mercury and Air Toxics Standard. The Utilities’ emissions testing performed in recent years indicate that The Utilities can comply with the limits in the Mercury and Air Toxics Standard for all of the Nixon and Drake coal-fired boilers with minimal capital investment. It is expected that the combination of planned scrubbers, activated carbon injection, and existing baghouses will be adequate to meet these new standards. While additional monitoring, testing and reporting will be required capital investment is expected to remain at less than $1 million for all coal-fired units combined. The Utilities has implemented a compliance program for the Mercury and Air Toxics Standard.

Since the publication of the greenhouse gas “endangerment finding” in 2009, new regulations, proposed regulations and policies have been developed to regulate carbon dioxide and other greenhouse gases. In May 2010, the EPA issued its final “Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule” (the Tailoring Rule) for regulating greenhouse gas emissions. In August, 2015 the EPA submitted its final “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility

Generating Units" (the "Clean Power Plan") for Federal Register publication, along with a proposed model implementation plan for states and New Source Performance Standards for new coal and natural gas-fired generating units. The Clean Power Plan creates a process for reducing carbon dioxide emissions from existing power plants on a state-by-state basis to reach a national reduction goal by 2030. The Clean Power Plan and proposed model rule encourage emissions trading to achieve these goals, although it remains to be seen whether such trading will be implemented at the state and/or regional level. In 2015, the Utilities evaluated potential impacts of the Clean Power Plan as part of its Electric Integrated Resource Plan. As it is currently proposed, the Clean Power Plan would not necessarily result in closures of coal-fired generation but could restrict utilization of such units to meet specific reduction goals and create additional reliance on natural gas-fired generation and new sources of renewables. In February, 2016 the United States Supreme Court stayed the rule pending legal challenges. At the State level, however, the CDPHE is continuing to evaluate carbon dioxide emission reduction options. The Utilities will continue to evaluate potential impacts of the Clean Power Plan as part of its ongoing evaluation of its existing coal-fired generation, future resource needs, and any operational constraints that may be imposed through a state plan for implementation of the regulation. The New Source Performance Standards for new coal and natural gas-fired plants allows for construction of new coal-fired generation but only if it can meet new and stringent carbon dioxide limits through costly carbon controls.

In December 2014, the EPA issued a final rule regarding "Coal Combustion Residuals," which are also referred to as "coal combustion byproducts" or "coal ash." The rule establishes requirements for the impoundment and disposal of Coal Combustion Residuals under subtitle D of the Resource Conservation and Recovery Act as a non-hazardous waste. Additional capital expenditures will be needed beyond 2026 when the existing ash landfill reaches capacity. Utilities currently disposes of its Coal Combustion Residuals in a "dry" form at its Clear Spring Ranch Solids Handling and Disposal facility under a County solid waste disposal authorization known as a "Certificate of Designation."

In February 2012 the CDPHE adopted revisions to Section 9 (regarding waste impoundments) of its "Regulations Pertaining to Solid Waste Sites and Facilities." Additional capital investment in the range of $1.0 million to $9.0 million for existing impoundments may be required to meet these revisions in the 2018-2020 timeframe. The Utilities expects to receive clarity from the CDPHE in 2017 regarding the extent for impoundment related capital investment following their review of the Utilities' preliminary impoundment classification submittals. The revised regulation will require Nixon to obtain a "Certificate of Designation" from El Paso County.

In September 2015, the EPA finalized Effluent Limit Guidelines for electric power generating stations. The Nixon plant is a zero discharge facility and is not affected by the final rule. The Birdsall plant does not have any new requirements under the final rule. The Drake plant will be required to modify the boilers' bottom ash systems by November 2018 at an estimated cost of less than $0.5 million.

Except as described in the preceding paragraphs of this section, the Utilities believes that the air and water pollution control facilities at its electric generating units are sufficient so that those facilities will remain in compliance with all present air and water pollution laws and regulations.

Certain Factors Affecting the Electric Utility Industry

The electric utility industry in general has been, or in the future may be, affected by a number of factors which could impact the financial condition and competitiveness of an electric utility and the level of utilization of generating and transmission facilities. In addition to those discussed elsewhere in this Official Statement, such factors include, among others, (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements; (b) changes resulting from conservation and demand side management programs, more cost-effective renewable resources, distributed generation, energy storage and smart-grid opportunities on the timing and use of electric energy; (c) changes resulting from a national energy policy; (d) effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions, and "strategic alliances" of competing electric and natural gas utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity; (e) the proposed repeal of certain federal statutes that would have the effect of increasing the competitiveness of many investor-owned utilities; (f) increased competition from independent power producers and marketers, brokers and federal power marketing agencies; (g) "self-generation" by certain industrial and commercial customers and other distributed generation sources; (h) issues relating to the ability to issue tax-exempt obligations to finance and refinance projects; (i) effects of inflation on the operating and maintenance costs of an electric utility and its facilities; (j) changes from projected future load requirements; (k) increases in costs and uncertain availability of capital; (l) shifts in the availability and relative costs of different fuels; (m) sudden, drastic increases in the price of energy purchased on the open market that may occur in times of high public demand in an area of the country experiencing high peak demand; (n) the credit quality of third-party power providers; and (o) the national, state, and local economic conditions. Any of these factors (as well as other factors) could have an impact on the financial condition of any given electric utility and likely will affect individual utilities in different ways.

The Utilities cannot predict what effects such factors will have on its operations and financial condition, but the effects could be significant. The discussion contained in this Official Statement does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof.

FERC Electric Transmission Regulation

The Federal Energy Regulatory Commission ("FERC") regulates interstate-related electric transmission services under the Federal Power Act, 16 USC § 791a, et seq. FERC jurisdiction under the Federal Power Act does not extend to the Utilities. However under FERC precedent, FERC-jurisdictional electric utilities (mainly investor-owned utilities) could deny the Utilities interstate electric transmission services if the Utilities does not provide those electric utilities access to the Utilities electric transmission system on the same terms and conditions that the Utilities provides to itself ("Reciprocal Service"). For the purpose of ensuring that the Utilities would not be denied such Reciprocal Service, the Utilities maintains an Open Access Transmission Tariff ("OATT") for interstate electric transmission service that is similar to the pro forma OATT prescribed by the FERC for its jurisdictional utilities. The FERC pro forma OATT is generally adopted (with minor variations) by FERC-jurisdictional electric utilities for those utilities interstate transmission services.

NERC Regulation

The North American Reliability Corporation ("NERC") establishes and enforces reliability standards, including critical infrastructure protection standards, for the bulk power system. The critical infrastructure protection standards focus on controlling access to critical physical and cyber security assets. Compliance with these standards is mandatory. The maximum penalty that may be levied for violating a NERC reliability standard is $1 million per violation, per day. The Utilities is in the Western Interconnection, and in that interconnection NERC standards are enforced and monitored by NERC and by its delegate the Western Electricity Coordinating Council ("WECC").

The Utilities has self-reported some violations of NERC reliability or critical infrastructure protections standards to WECC and has paid the necessary fines. The Utilities was audited by WECC during 2015. That audit listed minor violations of the NERC standards, and those violations were remediated and the review terminated in 2016 with no penalty assessed to the Utilities. The Utilities has formal programs, processes, and policies in place to promote compliance with these NERC standards. However, it is not possible to predict whether the Utilities will have future violations or what the fines for such violations might be.

THE GAS SYSTEM

The Gas System operates a local distribution system which supplied natural gas to approximately 198,000 customers in 2016 in a 527 square mile service area. In addition to the City, the service area includes Manitou Springs, the Academy, the northerly portion of Fort Carson and certain unincorporated portions of the County. The Gas System purchases gas under contracts with a variety of gas suppliers including nationwide marketing companies as well as national and regional production companies. The Academy, Peterson and Fort Carson are currently served under a Government Services Administration Areawide Contract.

The Utilities has the natural gas franchise to serve Manitou Springs through July 2024. No franchise fee is paid upon the gross revenues received from natural gas service to Manitou Springs. The Utilities also has the natural gas franchise to serve portions of the City of Fountain through December 2033. As part of its agreements with the City Fountain, the Utilities will pay the City of Fountain a franchise fee equal to 3% of the gross revenues from the natural gas service provided to customers within Utilities certificated area located in the City of Fountain's municipal limits.

While the Gas System is subject to federal and state environmental regulations, the Utilities does not anticipate the incurrence of extraordinary costs for its compliance with such regulations.

The Gas System facilities consist of approximately 2,500 miles of natural gas pipe mains, approximately 162,000 service lines. The Utilities undertakes improvements to maintain the Gas System and to provide capacity for increased customer demand. It does not anticipate the incurrence of material costs for extraordinary capital improvements to the Gas System.

Gas Rates

The following table sets forth rates as they relate to residential and commercial service provided by the Gas System. As noted in the table, the Utilities imposes a gas cost adjustment to pass through to its customers changes in costs of gas from its suppliers. As with the electric cost adjustment, the gas cost adjustment calculation considers the forecasted cost of gas and is subject to revision as often as monthly, depending on market conditions.

Natural Gas Rates
(As of July 1, 2017)

Residential and Small Commercial Service:		
The bills are the sum of:		
Gas Cost Adjustment[(1)]	-- Per 100 cubic feet	$ 0.2367
Gas Capacity Charge	-- Per 100 cubic feet	0.1073
Access and Facilities Charges	-- Per day	0.3930
	-- Per 100 cubic feet	0.1645
Commercial Service Large:		
The bills are the sum of:		
Gas Cost Adjustment[(1)]	-- Per 100 cubic feet	0.2367
Gas Capacity Charge	-- Per 100 cubic feet	0.0894
Access and Facilities Charges	-- Per day	0.7860
	-- Per 100 cubic feet	0.1480

(1) The Utilities' gas rates include a gas cost adjustment, which reflects changes in the costs of gas from its suppliers. The current gas cost adjustment was effective February 1, 2017 and can change monthly.

The City Council is authorized to determine rates charged for gas service within the Gas System's service area (both inside and outside City limits). However, if the rates to be charged for the same customer classifications are different for customers within and outside City limits, then a state statute requires that rates to be charged to customers outside the City limits be reviewed and approved by the PUC before becoming effective. The statute also provides that the PUC has jurisdiction to resolve any conflict relating to the rates established by the City Council upon the filing of a complaint by 5% of the affected customers outside the City limits. Under the statute, the City Council is ordinarily required to give at least 30 days' notice to the public prior to holding a public hearing to consider proposed base rate changes. The statute allows rate changes absent the public notice and hearing for good cause. By virtue of the ordinances establishing the rate making process for the Utilities, a 30 day public notice is not provided for changes to the gas cost adjustment. Published notice is provided within 10 days after City Council approval for the gas cost adjustment.

Gas Sales and Revenues

The ten largest customers of the Gas System during 2016, ranked by sales volume in CCF, represented 34,782,872 CCF, or 16.5% of sales (excluding interdepartmental and miscellaneous sales), and $10.4 million or 8.1% of revenues during that period (excluding interdepartmental revenues and miscellaneous revenues).

The number of active residential meters served by the Gas System was 172,807, 175,913, 178,703, and 180,032 at the end of 2013, 2014, 2015, and 2016 respectively. The average annual use per residential customer was 748 CCF in 2013, 714 CCF in 2014, 671 CCF in 2015, and 657 in 2016.

The following tables set forth the Utilities' gas sales and revenues by customer class for the past five years (excluding information relating to the component units for the Public Authority for Colorado Energy described in Note 18 to the Audited Financial Statements included in Appendix A to this Official Statement):

	Gas Throughput (Mcf)[1] 14.65 p.s.i.a.) Fiscal Year Ended December 31				
Customer Class	***2012***	***2013***	***2014***	***2015***	***2016***
Firm Sales:					
Residential	11,022,650	12,932,320	12,552,841	11,992,038	11,826,770
Commercial	6,075,021	7,371,441	7,067,745	6,573,449	6,480,441
Special Contract Service	387,741	1,630,025	1,810,950	1,644,809	1,887,313
Interruptible Sales:					
Industrial Rate #2	61,494	74,051	62,435	75,334	28,827
Industrial Rate #3	634,346	667,237	626,491	728,013	796,867
Subtotal	18,181,252	22,675,074	22,120,462	21,013,643	21,020,218
Interdepartmental – Firm and Interruptible	396,003	257,717	368,398	106,957	104,828
Total Gas Sales Volume	18,577,255	22,932,791	22,488,860	21,120,600	21,125,046
Gas Transportation Volume	2,420,802	1,141,379	1,262,342	1,259,999	1,242,367
Total Throughput Volume	20,998,057	24,074,170	23,751,202	22,380,599	22,367,413
Less: Interdepartmental Sales	(396,003)	(257,717)	(368,398)	(106,957)	(104,828)
Net Throughput Volume	20,602,054	23,816,453	23,382,804	22,273,642	22,262,585
Total Number of Active Gas Meters as of Year End	190,489	192,872	195,832	198,347	200,841

(1) "Mcf" = one thousand cubic feet

Customer Class	*Gas Revenue Fiscal Year Ended December 31* 2012	2013	2014	2015	2016
Firm Sales:					
Residential	$114,602,613	$114,265,884	$115,688,686	$101,933,786	$ 83,918,427[1]
Commercial	53,432,626	56,112,429	54,479,060	45,128,542	33,518,368
Special Contract Service	8,561,732	10,236,661	12,355,633	8,954,409	8,823,096
Interruptible Sales:					
Industrial Rate #2	393,769	393,803	350,691	358,272	90,592
Industrial Rate #3	2,523,962	3,177,231	3,397,259	2,981,366	2,988,996
Subtotal	$179,514,702	$184,186,008	$186,271,329	$159,356,375	$129,339,479
Interdepartmental – Firm and Interruptible Sales:	2,036,054	1,591,784	2,240,652	1,060,555	957,890
Total Gas Sales Revenue	$181,550,756	$185,777,792	$188,511,981	$160,416,930	$130,297,369
Gas Transportation Revenue	3,348,661	2,248,841	2,322,513	2,362,471	2,285,653
Miscellaneous Revenue	22,618,002	20,143,236	22,252,071	13,554,126	3,561,429
Total Gas Revenue	$207,517,419	$208,169,869	$213,086,565	$176,333,527	$136,144,451
Less: Interdepartmental Sales	(2,036,054)	(1,591,784)	(2,237,279)	(1,060,555)	(957,890)
Net Gas Revenue	$205,481,365	$206,578,085	$210,849,286	$175,272,972	$135,186,561

(1) In 2015, Utilities over collected on the Gas Cost Adjustment. As a result, the Gas Cost Adjustment was adjusted in January, February, August, and November of 2016 to reduce the over collection. These adjustments resulted in lower revenue of approximately $10.6 million in 2016.

Gas Supply

The Utilities contracts for sufficient firm transportation capacity and supplies to meet its firm peak day needs. The Utilities defines peak day conditions as a day with an average temperature of -13 degrees Fahrenheit. The Utilities' goal is to hold a diversified portfolio of gas supplies, pipeline transportation and storage services in order to provide reliability and economic efficiency in meeting its supply obligations. Notably, the Utilities entered into a prepaid gas supply agreement with Merrill Lynch & Co., Inc. and Merrill Lynch Commodities, Inc. in June 2008. This agreement provides for about 20% of the Utilities retail natural gas load with firm supplies priced at approximately $5 million below market for each year of its 30 year term.

The Utilities' firm gas supply portfolio is comprised of multiple contracts with terms ranging from three months to thirty years. The expiring contracts are competitively bid by the suppliers each year, usually during the spring. In addition, the Utilities purchases approximately 20% of its annual gas supply needs on a short-term (30-day or less) basis, giving the Utilities the flexibility to react to warmer than normal conditions without having to manage excess firm commitments, and providing the flexibility to take advantage of short-term drops in gas prices. The staggered terms of the supply contracts help shape supply commitments to better match load requirements, and ensure the Utilities can acquire and replace supplies in an orderly fashion.

In addition to maintaining a diversified portfolio of contracted supplies and assets, the Utilities actively pursues opportunities to reduce costs and realize value from its gas supply assets when they are not actively in use to serve the Utilities' load. This "optimization" process includes releasing transportation and storage capacity to third parties to monetize short term capacity surpluses. These gains are entirely credited to the Utilities' cost of service, thereby reducing overall customer costs.

The Utilities maintains firm contracted natural gas pipeline capacity on Colorado Interstate Gas Company, an interstate pipeline, to transport natural gas supplies to the Gas System's distribution facilities. In addition, Utilities maintains contracted natural gas storage services on Colorado Interstate Gas Company and Tallgrass Interstate Gas Transmission, and is a contracted customer and part owner (5%) of Young Gas Storage Company LLC. The Utilities also owns and operates a peak shaving propane air plant inside the boundaries of the Gas System itself.

Gas Price Hedge Program

Historically, the Utilities has sought to reduce energy price uncertainty in an effort to allow customers to better plan the utilization of utility services and their respective costs. To support the effort to reduce energy price uncertainty, the Utilities implemented a natural gas hedging program which required specific volumes to be hedged according to a defined schedule. This hedging program has successfully reduced price uncertainty through periods of high natural gas price volatility. However, following an extensive program evaluation in 2010 and 2011, the Utilities determined that changes should be made to this program to more effectively balance volatility reduction with program costs. As a result of this evaluation, the Utilities suspended its hedging activities in February 2012 and currently has no gas hedges in place. The suspension is under continual evaluation and will be lifted when market conditions indicate that the risk of higher market pricing outweighs the benefit of participation in the current low price environment. In addition, the Utilities continues to maintain an active gas cost adjustment process whereby natural gas cost volatility can be quickly passed through to customer rates.

The Energy Risk Management Policy requires that the Utilities' counterparties to financial energy transactions be on an approved counterparty list. To be on this list, counterparties must have a minimum rating of BBB issued by S&P, a minimum rating of Baa2 issued by Moody's, a minimum rating of BBB issued by Fitch Ratings, or be specifically approved by the Utilities' Risk Management Committee. The Energy Risk Management Policy limits the amount of counterparty credit exposure according to the counterparty's credit rating.

THE WATER SYSTEM

In 2016, the Water System served an estimated population of approximately 481,000 persons, including City residents and customers living in Ute Pass communities west of the City, military bases, and other suburban areas outside the City limits. In 2016, the Water System delivered 72,624 acre- feet (23.7 billion gallons) of potable water to the distribution system. This compares to water deliveries of 67,159 acre feet (21.9 billion gallons) in 2015, 70,255 acre-feet (22.9 billion gallons) in 2014, and 66,413 acre- feet (21.6 billion gallons) in 2013. When fully developed as planned (approximately 2070), the City's water resources will reliably meet potable water demands of approximately 136,000 acre feet. Presently, developed potable water supply sources and infrastructure can meet demands of roughly 95,000 acre feet. See "– Water Supply and Raw Water Delivery" below.

Water Rates and Development Charges

The Utilities' base water rates, which became effective January 1, 2017 are as follows:

Water Rates – Inside City

Single Family Residential Service	
Service Charge—Per meter, per day[(1)]	$ 0.7079
Commodity Charge—Per cubic foot	
1 through 999 cubic feet	0.0349
1,000 through 2,499 cubic feet	0.0654
2,500 cubic feet and greater	0.0988
Non-Residential Service	
Service Charge—Per meter, per day[(2)]	1.6562
Commodity Charge—Per cubic foot (Nov-April)	0.0424
Commodity Charge—Per cubic foot (May-Oct)	0.0637

(1) For meters from 5/8 to 1 inch. Higher rates apply for larger meter sizes.
(2) For meters less than 2 inches. Higher rates apply for larger meter sizes.

Water Rates – Outside City

Single Family Residential Service	
Service Charge—Per meter, per day[(1)]	$ 1.0619
Commodity Charge—Per cubic foot	
1 through 999 cubic feet	0.0524
1,000 through 2,499 cubic feet	0.0981
2,500 cubic feet and greater	0.1482
Non-Residential Service	
Service Charge—Per meter, per day[(2)]	2.4843
Commodity Charge—Per cubic foot (Nov-April)	0.0636
Commodity Charge—Per cubic foot (May-Oct)	0.0956

(1) For meters from 5/8 to 1 inches. Higher rates apply for larger meter sizes.
(2) For meters less than 2 inches. Higher rates apply for larger meter sizes.

Pursuant to the requirements set forth in the City Code, City Council may declare a Stage II water shortage when the Utilities' Chief Executive Officer informs City Council that the analysis required by the City Code or the existence of an emergency shortage indicates that the Stage I response is insufficient to reduce demands to a level in proportion to the severity of the shortage. The City is currently in Stage I (Level A) with approved commodity charges in effect.

The Utilities also assesses a water development charge to partially recover the costs of water supply infrastructure and services provided to new customers connecting to the Water System, whether inside or outside the City limits. The water development charge for commercial and industrial customers is based on meter size and varies from $9,292 and $13,938 for ¾" and smaller meters inside and outside the City limits, respectively, to $154,867 and $232,300 for 4" meters inside and outside the City limits, respectively. The methodology for calculating development charges for meter sizes above ¾ inches and less than 6 inches was changed in 2012, resulting in a decreased charge for these meters. In January 2017 the methodology for calculating development charges for meters 6" and larger was changed from a flow based formula to a charge based upon the meter capacity to be consistent with the methodology used for meter sizes up to 4 inches. For single family residential customers, the water development charge is based on lot size and varies from $5,887 and $8,830 for smaller lots inside and outside the City limits, respectively, to $12,913 and $19,939 for larger lots inside and outside the City limits, respectively. The water development charge for individually metered multi-family residential customers is $5,295 and $7,942 inside and outside the City limits, respectively. The water development charge for master metered multi-family residential customers are based upon the commercial meter rates and the size of the service. Virtually all water sold within the Water System is metered.

Water Sales and Revenues

During 2016, the Utilities' ten largest water customers ranked by sales volume in cubic feet accounted for 419,815,239 cubic feet, or 15.6% of Utilities' metered sales (excluding interdepartmental, irrigation and miscellaneous sales), which represented $17.9 million, or 10.8% of revenues for metered sales (excluding interdepartmental, irrigation and miscellaneous sales).

The number of active residential meters served by the Water System was 129,403, 130,770, 132,259, and 133,861 at the end of 2013, 2014, 2015, and 2016, respectively. The average annual use per residential customer was 13,203 cubic feet in 2013, 13,522 in 2014, 12,672 in 2015, and 12,842 in 2016.

The following tables set forth the Utilities' water sales and revenues by customer class for the past five years (excluding information relating to the component units described in Note 18 to the Financial Statements included in Appendix A to this Official Statement):

Customer Class	Water Sales (CCF) [1] Fiscal Year Ended December 31 2012	2013	2014	2015	2016
Residential (City)	22,710,977	16,989,813	17,587,329	16,667,144	17,096,449
Residential (Suburban)	123,031	95,263	95,202	92,880	93,316
Commercial (City)	8,651,291	6,569,462	7,498,461	7,251,608	7,751,545
Commercial (Suburban)	40,681	29,031	31,928	29,043	211,646
Contract Sales	2,448,431	1,923,949	2,112,916	1,816,151	1,757,080
Interdepartmental Sales	2,782,245	2,610,892	2,182,864	2,473,356	2,040,086
Irrigation and Miscellaneous Sales[2]	6,863,857	2,777,419	2,950,772	9,101,961	8,058,086
Total Metered Sales	43,620,513	30,995,829	32,459,472	37,432,143	37,008,208
City Use and Losses (Est.)	3,123,739	2,431,834	2,571,442	2,554,012	3,733,332
Total Water Delivered for Sales	46,744,252	33,427,663	35,030,914	39,986,155	40,741,540
Less Interdepartmental Sales	(2,782,245)	(2,610,892)	(2,182,864)	(2,473,356)	(2,040,086)
Net Water Delivered for Sales	43,962,007	30,816,771	32,848,050	37,512,799	38,701,454
Total Number of Active Water Meters as of Year End	135,901	137,619	139,115	140,601	142,298

(1) "CCF" is an abbreviation for 100 cubic feet, which represents approximately 748 gallons.
(2) Raw water spot sales volumes excluded.

Customer Class	Water Revenues Fiscal Year Ended December 31 2012	2013	2014	2015	2016
Residential (City)	$110,366,550	$ 92,910,645	$104,408,732	$ 98,723,333	$111,102,213
Residential (Suburban)	974,112	888,155	980,631	954,447	1,075,351
Commercial (City)	40,232,129	32,876,546	41,727,967	40,514,222	45,549,803
Commercial (Suburban)	323,506	264,116	311,993	285,437	339,421
Contract Sales	8,220,260	6,320,595	7,797,063	6,816,166	7,722,518
Interdepartmental Sales	4,378,180	4,069,614	3,341,849	4,527,252	4,594,028
Irrigation and Miscellaneous Sales[1]	7,893,268	4,876,710	5,759,376	3,895,849	5,017,003
Total Metered Revenues	$172,388,005	$142,206,381	$164,327,611	$155,716,706	$175,400,337
Miscellaneous Revenues	1,412,967	1,171,291	1,230,102	1,697,670	1,851,145
Total Water Revenues	$173,800,972	$143,377,672	165,557,713	157,414,376	177,251,482
Less Interdepartmental Sales	(4,378,180)	(4,069,614)	(3,404,726)	(4,527,252)	(4,594,028)
Net Water Revenues	$169,422,792	$139,308,059	$162,152,987	$152,887,124	$172,657,454

(1) Raw water spot sales volumes excluded.

Water Demand

Per capita water demand in the City varies considerably from year to year depending upon weather conditions, economic conditions, water restrictions, and other factors. In 2016, the total demand on the Water System of 20.9 billion gallons of potable water (total metered water sales) resulted in an estimated average metered per capita demand on the Water System of 135 gallons per day ("gpd"). This compares to estimated average metered per capita use of the Water System of 127 gpd in 2015 and 135 gpd in 2014.

The Utilities estimates that it will have sufficient water supply to meet the growing needs of the area served by the Water System until approximately the 2070 decade under present population and per capita demand projections, assuming retention of all present water resource entitlements and timely development of necessary additional facilities and sources as discussed below under "-Capital Improvements to the Water System." The loss of entitlement, delays in the development of water resources, or growth of population and/or per capita demand in excess of projections, or other similar factors, could result in the Utilities not meeting Water System level of service criteria, which may result in interim water supply shortages and reductions in total system wide storage levels below approved risk tolerance thresholds. See "-Water Supply and Raw Water Delivery" below.

Drought Conditions in the Region

Colorado, along with most of the western United States, experiences recurring cycles of drought. The Utilities' water supply system is designed and operated to withstand recurring cycles of drought through its complex network of storage reservoirs, water delivery systems, and related water infrastructure. Utilities relies more heavily on storage to meet customer demands during periods of drought when water system inflows are below average. Although the western United States has been experiencing general drought conditions of varying degrees at different locations for the last fifteen years, the specific effects on local water providers varies greatly. The City's watersheds experienced below average snowpack and water system yield during the winters of 2011-2012 and 2012-2013 and persistent hot and dry weather which resulted in drought conditions. However, in 2013, the Utilities implemented a Comprehensive Drought Response Plan and supply side water management strategies to achieve significant water savings and minimize the decline in water storage levels. With subsequent years of improved snowpack and system yields, system-wide water storage has recovered to levels exceeding two and three quarters years of customer demand in storage. Utilities' goal is to maintain greater than one year of customer demand in system-wide storage to mitigate known and unknown uncertainties and risks to the water system. The Utilities' closely monitors its water supply situation and will continue to rely on a combination of water in storage, water system inflows, and effective management of these supplies to meet customer demands.

The snowpack from the winter of 2016-2017 was above average and the storage levels for the Utilities' reservoirs are slightly ahead of their seasonal averages.

Reliance on Colorado River Water Supply

The Utilities' water supply is heavily reliant on the Colorado River Basin. The Utilities, along with the other major Colorado Front Range water providers including Denver, Aurora and certain others, serve approximately 80% of Colorado's population and economy. Approximately 72% of the major Front Range water providers' supply comes from the Colorado River Basin. As a result, Front Range water providers, including the Utilities, have a large stake in the future of the Colorado River and how the challenges of increasing water demands, long-term drought, and climate change will be addressed.

The Colorado River Compact allocates Colorado River water according to specified formulas among seven western states (the Lower Basin States of Arizona, California, and Nevada and the Upper Basin States of Colorado, New Mexico, Utah, and Wyoming). Pursuant to this system of allocation, the Utilities' water rights are subject to the obligation of Colorado and the other Upper Basin States to ensure that they do not cause a river depletion below a certain ten-year rolling delivery requirement. If shortage conditions were experienced (e.g., as a result of a prolonged drought and resulting low streamflows) and the Lower Basin States did not receive deliveries consistent with the aforementioned ten-year rolling delivery requirement, it is possible that the Utilities would be unable to divert all or part of its Colorado River water rights entitlements due to their subordinate status in relation to the State's obligations under the Colorado River Compact. However, due to the potential severity of such an occurrence, the Utilities, along with other Front Range water providers are actively working on adaptation strategies for this unlikely event in coordination with downstream entities.

Currently the Upper Basin States of the Colorado River Basin have delivered in excess of their ten-year rolling delivery requirement to the Lower Basin States of 75 million acre-feet, having delivered over 90 million acre-feet to the Lower Basin States over the past 10 years. Colorado's share of that obligation is 51% of the 75 million acre-feet delivery requirement. The Upper Basin States are collectively well within their Colorado River Compact allocations and are at little risk of Colorado River curtailment in the foreseeable future.

There are, however, other concerns related to maintaining critical storage levels in Lake Powell and Lake Mead. Lake Powell elevations above the minimum power pool (i.e. the minimum elevation required to produce hydropower) are desired. Implementing proactive measures to protect the power pool in Lake Powell will reduce the potential impacts to power production. Critical Lake Mead water elevations are related to Lower Basin storage sharing agreements and Southern Nevada Water Authority water intake elevations. The Upper and Lower Basin States are both working on their respective contingency planning efforts in coordination with the U.S. Department of Interior.

The Utilities is actively involved in numerous planning efforts and studies and is closely monitoring the ongoing discussions that are occurring between the Upper and Lower Basin States, the Federal Government, and other stakeholders on issues involving the Colorado River. Front Range water providers, including the Utilities, are actively engaged in and monitoring a contingency planning process that is being developed by the Upper Basin States and U.S. Bureau of Reclamation to evaluate risks and develop potential mitigation strategies.

Water Facilities

The Water System's raw water storage capacity is approximately 242,800 acre-feet in 25 reservoirs. In addition, the Utilities has a long term contract for up to 28,000 acre-feet of water storage available as excess capacity in the Fryingpan-Arkansas Project. The Water System also has covered treated water storage capacity of approximately 108 million gallons.

The Water System presently includes six water treatment facilities located around the City, with a sustained rated water treatment capacity of 259.5 million gallons per day ("mgd") and a peak capacity of 268.0 mgd. Phase I of SDS water treatment plant capacity was placed in service in April 2016. This new plant increased the Water System's sustained rated water treatment capacity by 50 mgd and also provides treatment redundancy to existing facilities in the near term.

Peak water usage in a single day of approximately 182 million gallons occurred in July 2001. The Utilities believes that the Water System's current treatment capacity will be more than sufficient to meet the needs of Utilities customers with the addition of the SDS treatment capacity. Upon full development of the SDS treatment plant, the Water System's treatment capacity is expected to be sufficient until at least the 2040 decade.

The Water System has over 2,000 miles of water distribution system main, most of which have been constructed since 1954. The Water System's level of unaccounted water has historically been approximately 8.5% of water treated, including unmetered water such as fire flows, main breaks, and system leakage.

Water Supply and Raw Water Delivery

Over 60% of the City's raw water supply originates from the headwaters of the Colorado River system, while the remainder originates from the Arkansas and South Platte River systems.

Utilities recently completed its Integrated Water Resource Plan (the "IWRP") (discussed below) which provides a long-term strategic plan for providing a reliable and sustainable water supply to Utilities in a cost-effective manner. The planning process used in the IWRP is a new approach that is a departure from previous planning processes. Previous estimates of water supply used historical hydrology compared with a single set of assumed system infrastructure and future demand conditions to estimate a "firm yield" for the Water System (i.e., the annual amount of demands that the Water System can reliably meet without realizing a shortage). This backward looking analysis assumed that future conditions would basically be a repeat of the past. In contrast, the IWRP adopted a forward facing, risk-based planning approach in which multiple risks and uncertainties affecting future water raw water system performance were identified and analyzed in the context of multiple possible future scenarios. The analysis included a robust analysis of both climate and non-climatic factors potentially facing Utilities. Consistent with the adoption of a risk-based planning approach, the Utilities Board formally adopted three levels of service planning criteria to measure the performance of the

Water System under future conditions. These three criteria are an expansion of previous performance criteria. The level of service criteria include:

1) Reserve Storage Reliability: Maintaining a minimum of 1.0 years of demand ("YOD") in storage reserve at all times (100% reliability);

2) Operational Storage Reliability: Maintaining a minimum of 1.5 YOD in storage reserve at least 90 percent of the time (90% reliability); and

3) Demand Reliability: Meeting indoor customer demands at all times (100% reliability)

Based on lessons learned during the recovery from the most recent drought cycle and continual advancement in the understanding of hydrologic risks through the IWRP and other related water resource planning efforts, the Utilities has recognized that maintaining a minimum of 1.0 YOD of emergency storage is appropriate to mitigate against unforeseen or unprecedented risks to the Water System. Maintaining 1.5 YOD in storage at least 90 percent of the time represents a reasonable level at which to initiate shortage response analysis in accordance with the current shortage response policies. Under these policies, if the analysis shows that conditions warrant, shortage response, including watering restrictions and supply side options, may be implemented. This is consistent with historic practice in which Utilities' customers were in watering restrictions nine of the last sixty years, or approximately 15% of the time. Meeting indoor customer demands at all times (100% reliability) is critical for maintaining community health and safety.

Through the IWRP, the Utilities now evaluates the performance of the Water System by determining the maximum annual demand that can be reliably met by the Water System while maintaining the three level of service criteria (Reliably Met Demand). Reliably Met Demand allows for the concepts of risk based planning to be presented in a manner that is consistent with the previous firm yield methodology, allowing current evaluations of the Water System to connect to past evaluations. The Reliably Met Demand of the Water System was determined by running the Utilities' Operations and Yield Model under increasing demands with specific operational, climate, and risk tolerance assumptions until the three level of service goals were no longer collectively met for the Water System as it existed in 2016 (Existing System). The Operations and Yield Model was then run in the same manner to determine the Reliably Met Demand for the Water System as it is proposed to exist at community buildout. At this buildout future, the Existing System components were operated in combination with a balanced portfolio containing a diversity of demand management, supply, storage, reuse, and conveyance options that were recommended and approved in the IWRP for future implementation (Existing System plus Full Balanced Portfolio). The table below shows the current estimated system Reliably Met Demand firm yield for developed (Existing System 2016) and undeveloped (Existing System plus Full IWRP Balanced Portfolio) system configurations. This data represents the contribution to the total Reliably Met Demand by system component for the two system configurations.

	Reliably Met Demand (formerly Firm Yield)	
	acre-feet / year	***million gallons per day***
Developed System		
Local System	24,000	21.4
Blue River Pipeline	7,400	6.6
Otero Pipeline	36,500	32.5
Fountain Valley Conduit	8,400	7.5
Southern Delivery System (Phase I)	18,700	16.7
Total Developed System	**95,000**	**84.7**
Undeveloped System		
Full IWRP Balanced Portfolio	41,000	36.6
Full System at Buildout	**136,000**	**121.3**

The table below shows the summarized estimates of Reliably Met Demand for current conditions, and expected conditions at community buildout. In future disclosures, the Utilities will present the Reliably Met Demand in the summarized format as shown below.

Reliably Met Demand of the Water System

System Configuration	Reliably Met Demand
Existing System (2016)	95,000 acre-feet/year (84.7 MGD)
Existing System plus Full IWRP Balanced Portfolio	136,000 acre-feet/year (121.3 MGD)

The Utilities believes its capacity for delivery of raw water from remote watersheds to local storage, including planned capacity additions and system improvements, will be adequate to meet demands until approximately the 2070 decade, when community buildout is expected to be complete. A diversity of demand management, supply, storage, reuse, and conveyance options (the IWRP Balanced Portfolio) will be implemented in the future to address water supply risks and satisfy the service area's needs between now and community buildout.

Reuse of Return Flows

The Utilities has the legal right (and in some cases, a legal obligation) to reuse and successively use to extinction the return flows that result from the initial use of its imported (or transmountain) water and certain other water sources. Based upon present projections, the total amount of return flow available for reuse is estimated to be approximately 50,000 acre-feet per year in the 2070 decade. Reuse of these return flows can occur directly through non-potable uses of reclaimed wastewater or indirectly both by the operation of exchanges (i.e. the trading of the Utilities' return flows for other water sources at different upstream locations) and through augmentation of well pumping and diversions.

The Utilities' non-potable reuse of return flows in the last ten years has ranged from a low of 2,871 acre-feet in 2016 to a high of 5,047 acre-feet in 2011 with the difference being attributable primarily to variations in demand due to weather, changes to the customer base and the implementation of water saving practices by large non-potable water users.

The Utilities exchanged approximately 35,000, 29,000, and 30,000 acre feet of water during the 2014, 2015, and 2016 water years (October 1 to September 30), respectively. These totals include local system exchanges, river exchanges and contract exchanges within the Arkansas River basin. Reuse by augmentation totals approximately 4,500 acre-feet annually.

Joint Water Authorities

The City is a participant in the Fountain Valley Authority and the Aurora-Colorado Springs Joint Water Authority (the "Aurora-Colorado Springs Authority"). Each of these authorities is a separate political subdivision of the State and is treated as a component unit of the City for financial reporting purposes.

The Fountain Valley Authority constructed a water treatment plant with 18 mgd capacity approximately 17 miles south of the City. The Utilities acts as operator of the plant under contract with the Fountain Valley Authority. The City is entitled to receive approximately 71% of the water treated at the Fountain Valley Authority plant. The remaining water is available to the other Fountain Valley Authority participants, which include Fountain, the Security Water District, the Stratmoor Hills Water District and the Widefield Water and Sanitation District, each of which owns and operates a water distribution system.

Under the applicable long-term contracts relating to the Fountain Valley Authority, the City is obligated to pay water treatment service charges to the Fountain Valley Authority and water conveyance service charges to the U.S. Bureau of Reclamation (the "Bureau") for conveyance of its water through the Bureau's Fountain Valley Conduit, which conveys raw water from the Pueblo Reservoir to the Fountain Valley Authority's treatment plant and treated water from the treatment plant to distribution reservoirs of the Fountain Valley Authority participants. See Note 17 to the Financial Statements included in Appendix A to this Official Statement.

As of December 31, 2016, Fountain Valley Authority had approximately $7.3 million in outstanding bonds and other obligations. Parity bonds and any parity securities subsequently issued by Fountain Valley Authority will be payable from and secured by a pledge of all net revenues (revenues after deducting operation and maintenance expenses, which do not include payments pursuant to the Conveyance Service Contract and Conveyance Service Subcontract) of the Fountain Valley Authority derived from the ownership and operation of the Fountain Valley Authority's Water Treatment Plant, including revenues derived under the Water Treatment Contract, and will be further secured by a pledge of certain funds created under the Resolution. The debt service on these bonds and other obligations is treated as a fixed cost to the member entities in proportion to their ownership interests in the Fountain Valley Authority. The Utilities' ownership interest in the Fountain Valley Authority is approximately 71% and, accordingly, the Utilities is ultimately responsible for approximately 71% of the debt service on these bonds and other obligations.

The City has a two-thirds participation share in the Aurora-Colorado Springs Authority. The Aurora-Colorado Springs Authority constructed a 66-inch diameter pipeline from the Twin Lakes Dam to the Otero Pumping Station intake pipeline. This pipeline is operated by Homestake Water Project staff on behalf of Aurora and Colorado Springs. The bonds for this project have been repaid and the Aurora-Colorado Springs Authority has no long-term debt outstanding. There are no current plans by either city to use the Aurora-Colorado Springs Authority for future system extensions. See Note 17 to the Financial Statements included in Appendix A to this Official Statement. The payments made by the City to the Aurora-Colorado Springs Authority are nominal.

The payments to be made by the City to the Fountain Valley Authority and the Aurora-Colorado Springs Authority are contractually required to be treated as Operation and Maintenance Expenses of the System payable out of the Gross Pledged Revenues of the System. See "DESCRIPTION OF THE BONDS—Security for the Bonds" and APPENDIX B—"THE BOND ORDINANCE—Equality of Lien." The payments made by the City to the Fountain Valley Authority for 2013, 2014, and 2015 were $9,114,265, $7,711,081, and $4,391,622 respectively.

Environmental Requirements Affecting Water Treatment

The Federal Safe Drinking Water Act, originally passed in 1974 and amended in 1986 and 1996, is enforced by federal and state agencies with responsibility over drinking water protection. The law requires actions by public water systems to protect drinking water from the source (e.g., rivers, reservoirs, and groundwater wells) to the customer's tap. This regulatory oversight applies to the public water systems' storage, treatment, and distribution facilities, as well as operational practices.

The Federal Safe Drinking Water Act authorizes the EPA to establish national health-based standards for the protection of drinking water from both naturally occurring and man-made contaminants. Additionally, the EPA maintains a list of unregulated contaminants that are not currently subject to any proposed or promulgated national primary drinking water regulation, but that are known or anticipated to occur in public water systems and may become subject to regulation in the future. As such, there is always the potential for new and/or more stringent standards that may impose additional costs to the Utilities, either to existing infrastructure or operations or to new water project development.

The Utilities' current long-term capital improvements forecast for the Water System addresses normal repairs and replacements in the treatment and distribution facilities to maintain both operational reliability and compliance with the Federal Safe Drinking Water Act and applicable regulations. The Utilities is required to provide a sufficient capacity and level of water treatment and disinfection necessary to meet EPA-established "maximum contaminant levels" for regulated contaminants as well as provide regular monitoring for these contaminants in its treatment plants and distribution systems. The Utilities' laboratory performs chemical, physical, and biological analyses of its finished water supplies, and is certified by the CDPHE for the analysis of drinking water.

The CDPHE and the EPA have the authority to enforce drinking water quality standards for the water supplied by the Water System. The CDPHE periodically conducts compliance inspections of the water treatment processes and laboratory monitoring provided by the Utilities. The laboratory is capable of meeting future analytical demands in response to system capacity additions and increased regulatory requirements. As part of the "consumer awareness" provisions of the Federal Safe Drinking Water Act, the Utilities is required to submit annual "consumer confidence reports" to its customers addressing the sources of its drinking water and the levels of regulated contaminants found in the drinking water through its monitoring programs. The Utilities' annual Water Quality Report to its customers consistently notes that the water treated and supplied by the Utilities meets applicable primary drinking water quality standards. Other provisions of the Federal Safe Drinking Water Act require the Utilities to maintain operator certifications, submit a Source Water Assessment report to the CDPHE, and maintain a cross-connection program.

Environmental Requirements Affecting Water Supply

Federal and state legislation often influences the Utilities' water development activities. Such legislation and regulations promulgated by federal and state agencies generally implement environmental policies concerned with land use, appropriation and allocation of water resources, and water quality. The constraints imposed by environmental laws and regulations could potentially limit the Utilities' current system yield or further expansion of existing water projects (particularly transmountain projects) as well as prohibit new project development. The most significant of these are the National Environmental Policy Act ("NEPA"), the Federal Land Policy and Management Act, the Wilderness Act of 1964, the Federal Wild and Scenic Rivers Act, the Clean Water Act, and the Endangered Species Act.

As part of the environmental assessment process under NEPA, reasonable alternatives to a proposed project must also be evaluated and reviewed as part of the federal decision-making process. This requirement has historically had the effect of both delaying projects and increasing project costs. The Federal Land Policy and Management Act authorizes the federal government to grant easements or issue special use permits for rights-of-way for water facilities crossing or located upon federal property and requires that special use permits include conditions necessary to protect the environment. Upon renewal or reopening of the various special use permits that the Utilities currently holds for the Water System, additional conditions, such as minimum stream flows or bypass requirements, might be imposed that could reduce the yield of related parts of the Water System in the future.

In addition, the federal government has designated large parcels of federally owned mountain land as controlled land use areas pending an evaluation for possible inclusion within the national wilderness preservation system under the Wilderness Act of 1964. The inclusion of land within a wilderness area can render a water source unusable due to access restrictions and federal reserved water rights claims, or force a change to a less desirable, more expensive alternative development or operation plan. Such designations have previously impacted the ability of the Utilities, through its joint partnership with the City of Aurora, to develop the remaining portions of the conditional water rights associated with the Homestake Project. Designation of 126,000 acres of land in the Holy Cross Wilderness Area in 1980 ultimately required that the Homestake conditional water rights be changed to new points of diversion located outside the Holy Cross Wilderness boundary. The Utilities is currently pursuing a joint use project with the City of Aurora and water users on the West Slope of Colorado to develop the remaining Homestake water rights and is evaluating a wide range of project configurations. The Utilities is continuously assessing new wilderness proposals that would impair the ability of the Utilities to operate its water system or fully develop its water rights entitlements. The Utilities has been successful in working with wilderness proponents, local stakeholders, and Colorado's congressional delegation to negotiate proposed boundaries for new wilderness additions that would accommodate existing water system operations and allow for future development of its conditional water rights.

The Federal Wild and Scenic Rivers Act is designed to protect certain free-flowing rivers identified by federal agencies and Congress has authority to designate segments of a river as wild, scenic, or recreational depending upon the presence of valued characteristics, such as recreational access, and other detracting factors, such as the degree of existing encroachment. Designation of a segment requires federal agencies to manage the river and adjacent lands to protect the identified valued characteristics and provides legal support for the appropriation of new federal water rights. Both of these effects present potential issues that could restrict the operations and development of the Water System. Currently, there are no river segments in Colorado that have been designated for inclusion in the National Wild and Scenic Rivers System which affect the Utilities' water system. There are, however, segments of the Upper Colorado River, Upper South Platte River, and Arkansas River within or above which the Utilities diverts water, operates water system infrastructure, or maintains existing decreed water rights for which alternative management plans to a Federal Wild and Scenic Rivers designation have been established. These alternative management plans have been developed by diverse groups of local stakeholders, including water providers, to defer or avoid Wild and Scenic Rivers suitability determinations or designations by the Federal land management agency. These plans are designed in a manner that appropriately balances protection of "outstandingly remarkable" environmental and recreational river values with the ability of water users to maintain water system yield, operate and maintain water infrastructure, and fully develop their water rights entitlements.

The Clean Water Act creates some potential for additional constraints on water operations and development activities. For example, in a United States Supreme Court case the Court considered hydrologic modifications as "pollution" under the Clean Water Act, and stated that instream flow requirements as special use permit conditions may be appropriate to protect designated stream uses. Similarly, recent federal courts of appeals decisions (outside the Utilities' jurisdiction) raise the issue of whether a permit is necessary to transfer raw water from one water body to another, while an EPA and Corps rulemaking proposal would expand the scope of federal jurisdiction under the Clean Water Act by redefining "waters of the U.S." Such conditions, along with those imposed under Section 404 of the Clean Water Act (relating to dredge and fill permits), Section 401 (relating to state certification of water quality conditions), Section 303(d) (relating to impaired water bodies and wasteload allocations), and those which may be necessary to meet Section 319 (non-point source best management practices) as well as new watershed-based requirements may increase the costs of future operations of the Water System and development of water resources. The EPA's emphasis on watershed planning and proposed modifications to the water quality standards program involve such issues as biological criteria, antidegradation review of permitted activities, and standards for clean sediment and nutrients, which could further impact water project construction and operation.

The conditions imposed under state and federal water quality regulations such as the Clean Water Act are determined on a case-by-case basis when projects are permitted based on an assessment of the impacts of the proposed project. As a result, the additional costs to operate the Water System and develop additional water sources as a result of these regulations is determined on a case-by-case basis and cannot be fully quantified at this time. The Utilities is actively engaged in and partnering with several water industry groups to oppose or ameliorate proposed regulations or administrative actions under Federal regulations such as the Clean Water Act which have the potential to adversely impact Utilities' water system. Recently, the Utilities has been actively involved in commenting on numerous Federal agency proposals including the EPA's proposed Waters of the U.S. and Water Transfers Rules and the Draft Technical Report on Protecting Aquatic Life from the Effects of Hydrologic Alteration.

Water Concerns

The City and the Utilities agreed, as part of the Pueblo County 1041 permit for the Southern Delivery System (the "SDS"), to "maintain storm water controls and other regulations intended to ensure that Fountain Creek peak flows resulting from new development served by SDS within the Fountain Creek basin are no greater than existing conditions." In furtherance of this commitment, the City adopted a new Drainage Criteria Manual that will greatly assist in ensuring that the storm water permit conditions are met. Efforts are being undertaken to have the Drainage Criteria Manual principles adopted on a regional basis. The City holds a Municipal Separate Storm Sewer System ("MS4") permit under the Federal Clean Water Act. The City's storm water system does not fall within the jurisdiction or responsibility of Utilities. On November 5, 2015, the EPA, through the U.S. Department of Justice (DOJ), informed the City that it intended to initiate an enforcement action against the City for violations of the City's MS4 permit. In November, 2016, after a year of unsuccessful negotiations, EPA and CDPHE sued the City for alleged violations of its MS4 permit. Both Pueblo County and the Lower Arkansas Water Conservancy District subsequently intervened in that ongoing litigation. The Court has ordered segmentation of the case, with trial of the first segment likely to be held early in 2018. It is not clear at this time when the action may be resolved through negotiation or trial, or what specific impact, if any, it will have on the City or the Utilities.

In April 2015, the Pueblo County Board of County Commissioners adopted a resolution directing the Pueblo County staff to investigate compliance with the storm water provisions of the Pueblo County 1041 permit for SDS. In May 2015, Pueblo County staff recommended to the Board of County Commissioners that there was adequate justification to order the City and the Utilities to show cause at a public hearing on why the Pueblo County 1041 permit should not be amended or suspended. The Pueblo County staff also recommended that the Board of County Commissioners delay the action on any show cause order until August 1, 2015. In April, 2016, negotiations with the County resulted in the execution of an intergovernmental agreement among Pueblo County, the City of Colorado Springs, and the Utilities pursuant to which the City and the Utilities agreed to spend $460 million on storm water control activities and capital projects over the next twenty years. Of this total, the Utilities agreed to contribute $3 million a year towards certain capital projects of benefit to the Utilities (escalated over time) and to act as a guarantor of the City's portion of the obligation (subject to reimbursement from the City under a separate agreement). Under this agreement the City will construct a total of 71 identified capital projects (or agreed upon substitutes therefore). All 2016 commitments under the intergovernmental agreement have been timely met.

Two perfluorinated compounds, perfluorooctane sulfonate (PFOS) and perfluorooctanoic acid (PFOA) were recently detected in some public groundwater wells that draw water from the Widefield Aquifer. The EPA has established a provisional health advisory of 0.2 micrograms per liter (parts per billion) for PFOS and 0.4 micrograms per liter for PFOA in drinking water to provide guidance regarding concentrations that should trigger action to reduce exposure to these unregulated contaminants. These wells, in part, serve as a potable water source to the communities of Security, Fountain, Widefield, and Stratmoor Hills which are located to the south of Colorado Springs. The water districts serving these neighboring communities have reduced or discontinued their use of Widefield Aquifer water until long-term solutions can be implemented to remove these compounds from well water. To assist neighboring communities in addressing their water quality concerns, the Utilities has entered into short-term water service agreements with Security Water District and Stratmoor Hills to establish emergency infrastructure interconnections and offset a portion of customer demands that were previously met by the Widefield Aquifer wells. The City of Fountain was able to eliminate the use of their wells through their participation in SDS. Through its participation in the Fountain Valley Authority, the Utilities is allowing the City of Fountain, the Widefield Water & Sanitation District, Stratmoor Hills Water District, and Security Water District to use a portion of the Utilities delivery capacity in the Fountain Valley Conduit on a temporary basis to deliver additional surface water supplies until treatment facilities are constructed to treat groundwater to levels below public health advisory levels.

Capital Improvements to the Water System

General. The City owns twenty-five earthen and rock-fill dams as a part of the Water System. The Utilities is required to have each of these dams inspected frequently by the State Engineer pursuant to the Colorado Rules and Regulations for Dam Safety and Dam Construction (the "State Dam Safety Regulations"). Specifically, the State Dam Safety Regulations require that dams have spillway capacity and structural integrity sufficient to withstand a major flood without failing or otherwise contributing to the magnitude of the flood. Based on such inspections of these dams, the Office of the State Engineer has recommended further study of certain facilities to address potential deficiencies in structural conditions or spillway capacity. Additionally, Rampart Dam is regulated by the FERC due to its connection to the Tesla hydroelectric generation facility. The FERC conducts annual inspections of Rampart Dam, and requires third-party inspections by an independent engineering consultant on a five-year cycle. Additional investigations, instrumentation requirements, or safety improvements to Rampart Dam may arise as a result of regulation by the FERC. The Utilities also completed its own comprehensive inspection program of the dams as part of the Raw Water Infrastructure Improvement Program, which also recommended certain additional improvements. In response to these studies' conclusions and recommendations, the Utilities intends to design and construct the recommended improvements at a cost averaging approximately $5 million per year through 2020 to remain in compliance with federal and state requirements.

Master planning efforts will continue for all water infrastructure. The Mesa Water Treatment Plant Master Plan Update was completed in 2015 and identified a capital improvement program of $28.5 million through 2020 at the Utilities' oldest water treatment plant. The Finished Water Distribution Master Plan is expected to be updated in 2017 to address future growth, resiliency, and redundancy needs of the distribution system. Other planning efforts expected to be completed in the next five years include Non-Potable System and Raw Water System Master Plans, a Raw Water Storage Master Plan, Dam Facility Plans, updates to the Potable Tank and Pump Station and Facility Plans, and remaining Water Treatment Plant Facility Plans.

Over the next ten years, the Utilities expects to implement an extensive capital improvement program focused on enhancing its water system infrastructure. Capital improvements to the Mesa Water Treatment Plant will allow the Utilities to more effectively treat and utilize its local water sources. To that end, the Utilities will also pursue capital improvements to the 33rd Street Diversion and Pump Station, which will increase the amount of local water that is delivered and treated at Mesa Water Treatment Plant. In addition, raw water system improvements on the Homestake System include phased pipeline replacement of sections of the 66-inch pipeline initiated in 2016 and planned to be completed in 2020 at an approximate cost to the Utilities of $1.5 million per year. Other Homestake infrastructure rehabilitation projects include the Arkansas River Diversion that is used as the back-up intake to the Homestake Project's Otero Pump Station, and is estimated to cost approximately $3.5 million. The Utilities will also actively pursue and acquire one or more storage locations near Fountain Creek or the Arkansas River for the primary purpose of managing reusable return flows and exchanges and will seek to acquire additional local and Arkansas Basin water rights as opportunities arise. In addition, $4 million annually will be expended on pump station and tank facility upgrades and improvement in the foreseeable future.

These projects are included in the Utilities' general capital improvement program. See "COLORADO SPRINGS UTILITIES – Capital Improvements."

On-going water main renewal and replacement efforts completed under the Water Main Replacement Program will invest approximately $30 million per year through 2020 and $13 million per year thereafter for the foreseeable future.

Long term water supply planning is an ongoing endeavor. The previous major planning effort was the Water Resource Plan, completed and approved by the City Council in 1996. Implementation of the Water Resource Plan has been carried out since its adoption, and most major projects identified in the plan, including SDS project, have been completed.

The latest iteration of water supply planning was the IWRP, a Utilities initiative completed in the first quarter of 2017. The IWRP presents a long-term strategic plan for providing a reliable and sustainable water supply to the Utilities' customers in a cost-effective manner. It provides a comprehensive approach to water resource planning that incorporates water supply and demand, water quality, infrastructure reliability, environmental protection, water reuse, financial planning, energy use, and regulatory and legal concerns. The IWRP included an extensive public and Utilities Board engagement process to answer key policy questions and help determine community risk tolerance levels and appropriate cost/benefit relationships for projects and programs to mitigate risks. The IWRP builds on and enhances the previous Water Resource Plan, by assessing the water needs and water supply of the community using a risk-based analysis approach in which risks and uncertainties affecting future performance of the Utilities Water System were identified and analyzed in the context of multiple future scenarios, rather than relying on a single set of assumed conditions and historical hydrology to obtain a static estimate of the firm yield of the Water System, or recommending a single path forward for meeting future water needs.

Implementation of the IWRP will require adaptive management in order to provide flexibility in the face of future uncertainty. Adaptive management will require careful tracking of key indicators of change such as annual water demand, per capita water demand, population, climate trends, regulatory changes, and changes in water rights administration, among other factors. These indicators will inform Utilities as to what projects, policies, and water supply strategies should be implemented at various points in time. This adaptive management approach will be used to determine a schedule for implementing a balanced water supply portfolio that contains a diversity of demand management, supply, storage, reuse, and conveyance options that meets level of service goals and appropriately balances costs and risks between now and community buildout.

Southern Delivery System. The Utilities has constructed a major regional water delivery project from Pueblo Reservoir known as the Southern Delivery System ("SDS"). All facilities constituting the first phase of SDS are substantially complete and water deliveries began on April 28, 2016.

Phase 2 of SDS will address water demand and water system capacity and water system redundancy beyond Phase 1, the components of which include a terminal storage reservoir, a return flow reservoir, expansion of the three pump stations' capacity, and expansion of the water treatment plant and finished water pumping capacity to serve additional pressure zones within the distribution system. For Phase 2, the most recent cost estimate from the 4^{th} quarter of 2016 is $184 million and it is currently anticipated to be constructed between 2020 and 2025, but could be accelerated or delayed, in whole or in part, depending upon future water demand and climate conditions (e.g. extended drought).

The Utilities remains in compliance with all of the listed permits and all other state and local land-use and permitting requirements applicable to SDS.

THE WASTEWATER SYSTEM

The Wastewater System provides wastewater services for the City and for those areas approved by the City Council on a long-term, contractual basis, including Peterson, Manitou Springs and the Stratmoor Hills Water and Sanitation District. An average of nearly 37.6 million gpd of wastewater is treated for a per capita treatment of about 88 gpd. This average has steadily decreased since 2007 due to improvements in the collection system, increased customer drought awareness and greater usage of water efficient appliances. As of December 2016, the Utilities owned and operated over 1,696 miles of sewer main.

Wastewater Rates

Wastewater treatment services are not metered (except for three contract customers), and residential charges for this service are based on the two lowest periods of water billed during the December, January, and February billing periods of each winter. Charges for non-residential customers are calculated monthly based on water usage (less irrigation and consumptive use adjustments, if applicable). The charges for users within the City and for suburban users are set forth below.

These charges became effective January 1, 2017.

Wastewater Treatment Service Charges

	Inside City	*Outside City*
Residential		
Service Charge — Per day	$0.5034	$0.7550
Quantity Charge — Each 100 cubic feet	2.4500	3.6700
Commercial		
Service Charge — Per day	0.9917	1.4875
Quantity Charge — Each 100 cubic feet	2.6900	4.0300

The City also assesses a surcharge to some large industrial customers whose discharge exceeds 25,000 gpd. The surcharge is adjusted periodically and is based on the average excess of biochemical oxygen demand and total suspended solids measured for each specific customer over normal discharge levels. The City imposes wastewater development charges for new connections to partially compensate for the cost of treatment plant expansion and other capital improvements. The wastewater development charges for single family residential customers were increased on January 1, 2010, and are now $1,868 within the City limits and $2,802 outside the City limits for customers outside the Jimmy Camp Creek service area. For customers inside the Jimmy Camp Creek service area, wastewater development charges for single family residential customers are $445 inside the City limits and $667 outside the City limits. The wastewater development charges for customers within the Jimmy Camp Creek service area cover only sludge conveyance and treatment. The liquid treatment plant for this area, if built, is expected to be funded by developers and those costs will be recovered directly from the developers for this area. Non-residential wastewater development charges vary based on water meter size, and range from $2,604 and $3,906 for ¾" and smaller meters within and outside the City limits, respectively, to $77,977 and $116,965 for 4" meters within and outside the City limits, respectively, for customers outside the Jimmy Camp Creek service area. Non-residential wastewater development charges within the Jimmy Camp Creek service area also vary based on water meter size, and range from $445 and $667 for ¾" and smaller meters within and outside the City limits, respectively, to $13,316 and $19,974 for 4" meters within and outside the City limits, respectively. Multi-family development charges are $1,213 inside the City limits and $1,820 outside the City limits for customers outside the Jimmy Camp Creek service area. Multi-family wastewater development charges for customers inside the Jimmy Camp Creek service area are $289 inside the City limits and $433 outside the City limits. In January 2017 the methodology for calculating development charges for meters 6" and larger was changed from a flow based formula to a charge based upon the meter capacity to be consistent with the methodology used for meter sizes up to 4 inches.

Wastewater Revenues

The following table sets forth the wastewater revenues by customer class for the past five years:

	Wastewater Revenues				
	Fiscal Year Ended December 31				
Customer Class	***2012***	***2013***	***2014***	***2015***	***2016***
Residential (City)	$49,374,879	$ 47,737,927	$49,293,132	$49,096,853	$50,469,281
Residential (Suburban)	116,245	98,139	105,599	106,849	126,142
Commercial (City)	14,852,780	15,126,309	14,857,395	14,448,748	15,770,265
Commercial (Suburban)	83,267	85,962	82,171	80,507	(712,843)
Contract Service	839,809	873,048	905,937	981,261	809,499
Interdepartmental	588,259	541,110	496,706	588,959	528,410
Subtotal	$65,855,239	$ 64,462,495	$65,740,940	$65,303,177	$66,990,754
Miscellaneous Revenues	954,571	968,398	1,308,560	1,005,183	1,026,415
Total Wastewater Revenues	$66,809,810	$ 65,430,892	$67,049,500	$66,308,360	$68,017,169
Less Interdepartmental Sales	(588,259)	(541,110)	(496,806)	(588,959)	(528,410)
Net Wastewater Revenues	$66,221,551	$ 64,889,782	$66,552,694	$65,719,401	$67,488,759
Total Number of Active Wastewater Accounts as of Year End	132,271	134,007	135,479	137,001	138,712

Wastewater Facilities

The Wastewater System operates two wastewater treatment facilities with a combined permitted capacity of 95 million gpd. The Utilities evaluates existing infrastructure and short and long range alternatives for meeting future demand on an ongoing basis.

Environmental Regulation

The Utilities operates the Las Vegas Street Water Resource Recovery Facility, which discharges treated wastewater to Fountain Creek, and the J.D. Phillips Water Resource Recovery Facility, which discharges treated wastewater to Monument Creek. Both facilities operate under the terms of Colorado Discharge Permit System ("CDPS") permits issued in 2006 pursuant to the Federal Clean Water Act. Under the CDPS permits, the Utilities is required to monitor wastewater discharges and report on a monthly basis the results of that monitoring to the CDPHE. In 2010, permit renewal applications were submitted to the CDPHE as required for both facilities. The permits were renewed and effective June 1, 2015 and expire on May 31, 2020.

In accordance with the CDPHE regulations, the Utilities is subject to public health protection limits for E. coli and turbidity applicable to the distribution system for reclaimed wastewater used for nonpotable purposes. The Utilities does not expect that additional capital or other expenditures will be required to comply with these regulations in the next several years.

The CDPS permits for the facilities require that when peak monthly throughput and treatment under normal circumstances reach 80.0% of facility design capacity, Utilities must initiate engineering and financial planning for additional treatment capacity, and that construction must be commenced when peak monthly throughput and treatment is at 95.0% capacity. For both facilities, the throughput and treatment are currently below these capacity standards. In 2016, peak monthly organic and hydraulic throughputs for the Las Vegas Street Water Resource Recovery Facility reached 43.7% and 41.4%, respectively. For the same period, peak monthly organic and hydraulic throughputs for the J.D. Phillips Water Resource Recovery Facility reached 39.7% and 43.0%, respectively.

A new ultraviolet disinfection system for the Las Vegas Street Water Resource Recovery Facility came on-line in January 2011 to both enable the facility to meet more stringent future E. coli limits as well as reduce operational and regulatory risks associated with chlorine gas disinfection. The CDPHE changed

Fountain and Monument Creeks' stream designations from "use-protected" to "reviewable" in July 2008. The Utilities saw the first impact of this change in the discharge permit renewal negotiations 2014 and 2015. This change may ultimately result in more stringent effluent limits for pollutants that have been detected in the discharge but are not limited by the treatment facilities' current CDPS permits. Additionally, pollutants that were limited by the previous CDPS permits were subjected to an "antidegradation" review. This resulted in monitoring requirements for cadmium (for the Las Vegas Street Water Resource Recovery Facility) and copper (for the J.D. Phillips Water Resource Recovery Facility) and compliance schedules to meet limits for these parameters. Source control or additional wastewater facility treatment facility controls for these parameters may be needed beyond 2019 in order to meet reduced effluent limits.

The CDPHE adopted regulations for reducing nutrients (nitrogen and phosphorus) in State waters through 2022 which became effective in September 2012. Additional capital investment will be required by the Utilities in order to meet these standards. Based on these regulations, approximately $5.63 million in capital investment will be required at the Las Vegas Street Water Resource Recovery Facility through 2022. Construction work is expected to be phased between 2016 and 2019 to allow sequencing of modifications in five aeration basins. Additional facility improvements will be accomplished during this same time period at a cost of $6.9 million. Compliance with new nutrient limits is required by 2019. The J.D. Phillips Water Resource Recovery Facility will be able to meet the new limits with a $1.5 million process improvement project which was completed in 2014. However, some nutrient regulatory scenarios could result in much greater capital investment being required after 2022.

As required by discharge permits, the Utilities has reported both sanitary sewer overflows ("SSOs") and reclaimed wastewater releases to regulatory agencies. SSOs can be caused by blockages in the sewer lines due to debris, tree roots and grease or can be caused by vandalism, construction damage, pump or pipeline failures, and severe flooding. In 2004, the CDPHE and the Utilities entered into a Compliance Order on Consent ("Consent Order") which addresses capacity and condition evaluations, along with the systematic repair, rehabilitation, and replacement of portions of the wastewater collection system through the year 2012. The Consent Order was reviewed and approved by the EPA. The Consent Order was subsequently amended in 2005, 2006, and 2010 to resolve SSOs that occurred through December 2009. On January 29, 2013, the Utilities submitted a "Notice of Completion" to the CDPHE for the Consent Order and subsequent amendments. In a letter dated March 8, 2013, the CDPHE informed the Utilities that the Notice of Completion ". . . was satisfactory and Colorado Springs has fully responded to and met its obligations pursuant to the Consent Order." As a result, the CDPHE formally closed the Consent Order and no further action is required from the Utilities on this matter.

The Clear Spring Ranch Resource Recovery Facility, which processes sludge from the Las Vegas Street Water Resource Recovery Facility and the J.D. Phillips Water Resource Recovery Facility, is currently regulated under federal sludge disposal regulations, the CDPHE's solid waste regulations, a County solid waste disposal authorization known as a "Certificate of Designation," and State air quality permits. Under these permits and related regulations, the Utilities is required to frequently monitor sludge and ground water quality.

In February 2012, the CDPHE adopted revisions to Section 9 (regarding waste impoundments) of its "Regulations Pertaining to Solid Waste Sites and Facilities." Additional capital investment in the range of $7.0 to $15.0 million for existing impoundments at the Clear Spring Ranch Resource Recovery Facility may be required to meet these revisions in the 2018 - 2020 timeframe. Utilities expects to receive clarity from the CDPHE in 2017 regarding the extent for impoundment-related capital investment following their review of Utilities' preliminary impoundment classification submittals.

In 2009, a "Wastewater Integrated Master Plan" was drafted and internally reviewed. This plan addresses the 10-year capital improvement projects needed for the wastewater collection system, wastewater treatment facilities and Clear Spring Ranch Resource Recovery Facility. It analyzes current capacity and future growth needs for wastewater system components. The plan also addresses the impacts of new regulations and plans for capital improvements necessary to keep the facilities in compliance with the new regulations.

Capital Improvements to the Wastewater System

The Utilities owns and operates over 1,696 miles of sanitary sewer pipelines throughout thirty separate basins in Colorado Springs. Beginning in 2000 the Utilities implemented several aggressive and comprehensive wastewater programs to systematically inspect, evaluate, prioritize, and rehabilitate its entire collection system. Included in the Wastewater System improvement programs are the Sanitary Sewer Evaluation and Rehabilitation Project, the Sanitary Sewer Creek Crossing Project, the Local Collectors Evaluation and Rehabilitation Project, Collection System Rehabilitation and Replacement Project, and the Manhole Evaluation and Rehabilitation Project. These Wastewater System improvement projects are independent of the Utilities' normal operation and maintenance programs and are intended, in part, to fulfill the requirements set by the CDPHE, and the terms and conditions of Pueblo County 1041 Permit for construction of SDS within Pueblo County.

Approximately 354,500 feet (67 miles) of Sanitary Sewer Evaluation and Rehabilitation Project pipe have been rehabilitated or replaced to date at a cost of approximately $75.0 million. The successor Collection System Rehabilitation and Replacement Project contracts were put into place in 2009 to continue the rehabilitation and replacement of pipes identified from continuing evaluations.

The Sanitary Sewer Creek Crossing Project work consists of the inspection, evaluation, the repair and/or replacement of sanitary sewer pipes and the erosion protection of various creek crossings structures in order to reduce the risk of spills, stoppages, and SSOs on pipelines that cross minor and major drainages. There are approximately 370 sanitary sewer creek crossings in the major and minor drainages that have been evaluated and are on a re-inspection schedule. Since 2005 the Utilities stabilized, replaced or eliminated 136 sanitary sewer creek crossings and/or longitudinal pipelines at an approximate cost through 2016 of $42,142,000. The 2017 budget for this project is approximately $3,000,000.

The Local Collectors Evaluation and Rehabilitation Project consists of the evaluation and rehabilitation of approximately 1,400 miles of sewer collection pipes less than 10-inch in diameter, which represent the majority of the Utilities' wastewater collection system. Approximately 83% of the sewer mains in the City of Colorado Springs are considered local collectors. The Local Collectors Evaluation and Rehabilitation Project builds upon Sanitary Sewer Evaluation and Rehabilitation Project by expanding the effort to include all sizes of sewer pipe. The total cost through 2016 associated with the Local Collectors Evaluation and Rehabilitation Project since 2008 is approximately $73,109,000. The 2017 budget for this project is approximately $3,320,000.

The Manhole Evaluation and Rehabilitation Project has been developed as a comprehensive program to provide the rehabilitation of sanitary sewer manholes throughout the Utilities' wastewater collection system and is designed to reduce the risk of spills, stoppages and SSOs, and to reduce infiltration and inflow at manholes throughout the collection system. There are about 33,000 manholes in the Utilities' collection system, of which approximately 28,000 were installed prior to 1993, or are in excess of 20 years old. 2015 was the seventh year of this project with a total cumulative project cost of approximately $3,638,000. The Manhole Evaluation and Rehabilitation Project was not funded in 2017.

The Collection System Rehabilitation and Replacement Project is an ancillary project to Sanitary Sewer Evaluation and Rehabilitation Project to provide an ongoing means to rehabilitate large diameter (greater than 10-inch) sewer pipe. The Collection System Rehabilitation and Replacement Project includes rehabilitation or replacement of large diameter sewer pipe that was not part of the Consent Order (sewer pipe that was installed after January 1, 1994) and pipe that is entering into a systematic 15 year inspection cycle. The project will also provide some funding for sewer pipes that need to be upsized because of capacity considerations. 2016 was the ninth year of this project with a total cumulative project cost of approximately $10,006,000. The 2017 budget for this project is approximately $2,000,000.