Q3 2016

Algonquin Power & Utilities Corp.

ALGONQUIN POWER & UTILITIES CORP.
Algonquin is a $5 billion North American diversified generation, transmission and distribution utility.

OUR VISION IS CLEAR. To be most admired by customers, communities and investors for our people, passion and performance.

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ALGONQUIN
Power & Utilities Corp.

Management Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and nine months ended September 30, 2016. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2016 and 2015. The MD&A should also be read in conjunction with APUC's annual audited consolidated financial statements for the years ended December 31, 2015 and 2014, and the annual MD&A for the year ended December 31, 2015. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Corporation's 2015 AIF.

This MD&A is based on information available to management as of November 10, 2016.

Caution concerning forward-looking statements and non-GAAP Measures

Forward-looking statements

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets as well as the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this MD&A and such expectations may change after this date. APUC reviews material forward-looking information it has presented, not less frequently than on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "per share cash provided by Adjusted Funds from Operations", "per share cash provided by operating activities", "Net Energy Sales", and "Net Utility Sales", are used throughout this MD&A. The terms "Adjusted Net Earnings", "per share cash provided by operating activities", "Adjusted Funds from Operations", "per share cash provided by Adjusted Funds from Operations", Adjusted EBITDA, "Net Energy Sales" and "Net Utility Sales" are not recognized measures under GAAP. There is no standardized measure of "Adjusted Net Earnings", Adjusted EBITDA, "Adjusted Funds from Operations", "per share cash provided by Adjusted Funds from Operations", "per share cash provided by operating activities", "Net Energy Sales", and "Net Utility Sales" consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "per share cash provided by Adjusted Funds from Operations", "per share cash provided by operating activities", "Net Energy Sales" and "Net Utility Sales" can be found throughout this MD&A. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Use of Non-GAAP Financial Measures

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses, and cash provided or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable) changes in working capital balances, acquisition expenses, litigation expenses, cash provided or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the Adjusted Funds from Operations of the entire facility is included in calculating the measure. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP.

Net Energy Sales

Net Energy Sales are a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where revenue generally is increased or decreased in response to increases or decreases in the cost of the commodity to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the revenue that is charged. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net Utility Sales

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. Where the Company manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's 2015 AIF.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flow to support a growing dividend and share price appreciation.

APUC's current quarterly dividend to shareholders is U.S. $0.1059 per common share or U.S. $0.4235 per common share per annum. Based on exchange rates as at November 10, 2016, the quarterly dividend is equivalent to Cdn $0.1427 per common share or Cdn $0.5708 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across three North American business units consisting of Generation, Distribution, and Transmission. The Generation Business Group ("Generation Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Distribution Business Group ("Distribution Group") owns and operates a portfolio of regulated electric, natural gas, and water distribution and wastewater collection utility systems; and the Transmission Business Group ("Transmission Group") is responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities.

Generation Business Group

The Generation Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. The Generation Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Generation Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 900 MW, 30 MW, and 335 MW, respectively. Approximately 86% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which have a production-weighted average remaining contract life of 15 years.

The Generation Group also has a portfolio of development projects that when constructed will add approximately 511 MW of generation capacity from wind and solar powered generating facilities that have a production-weighted average contract life of 21 years.

Distribution Business Group

The Distribution Group operates diversified regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 564,000 connections. The Distribution Group provides safe, high quality, and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

The Distribution Group's regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire and together serve approximately 93,000 electric connections.

The Distribution Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, Missouri, and New Hampshire and together serve approximately 293,000 natural gas connections.

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, Montana, and Texas and together serve approximately 178,000 connections.

Transmission Business Group

The Transmission Group is responsible for identifying, evaluating and capitalizing upon natural gas pipeline and electric transmission investment opportunities in North America. The Company believes that the Transmission Group complements the growth of both the Generation and Distribution Groups and enables APUC further opportunities for direct involvement in the North American energy industry.

Third Quarter Major Highlights

Corporate Highlights

Declaration of Canadian Equivalent Fourth Quarter Dividend of Cdn $0.1377 (U.S. $0.1059) per Common Share

On November 10, 2016, APUC announced that the Board of Directors of APUC declared the fourth quarter 2016 dividends of U.S. $0.1059 per common share. Based on the Bank of Canada noon exchange rate on the declaration date, the Canadian dollar equivalent for the fourth quarter 2016 dividends is set at Cdn $0.1377 per common share.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Total
U.S. dollar dividend	$0.0963	$0.1059	$0.1059	$0.1059	$0.4139
Canadian dollar equivalent	$0.1287	$0.1361	$0.1377	$0.1427	$0.5452

Strong Third Quarter Operating results

APUC recorded strong third quarter 2016 results relative to the same period last year.

	Three Months Ended September 30		
(all dollar amounts in $ millions except per share information)	2016	2015	Change
Adjusted EBITDA	**$91.4**	$70.2	**30%**
Adjusted Funds from Operations	**$61.0**	$54.3	**12%**
Adjusted Net Earnings per Share	**$0.09**	$0.06	**50%**

The Empire District Electric Company Merger Approvals Nearly Complete

On June 16, 2016, Empire's shareholders voted to approve the previously announced Agreement and Plan of Merger pursuant to which APUC, through a wholly owned subsidiary, will acquire The Empire District Electric Company ("Empire") (NYSE:EDE) and its subsidiaries (the "Acquisition").

Approximately 95.5% of votes cast voted in favour of the proposed merger.

The Transaction is expected to close early in 2017. Closing is subject to receipt of certain state and federal regulatory and government approvals, including approval of the relevant commissions of the states of Arkansas, Kansas, Missouri and Oklahoma (collectively, the "State Commissions"), the Federal Communications Commission (the "FCC"), the Committee on Foreign Investment in the United States and the Federal Energy Regulatory Commission (the "FERC"), and the expiration or termination of the waiting period under the Hart-Scott-Rodino Act.

Applications to four state commissions (AR, KS, MO, OK) as well as the FERC were filed on March 16, 2016.

On May 6, 2016, the FERC issued an order approving the proposed acquisition of Empire. The order did not contain any material conditions.

On May 12, 2016, the Oklahoma Corporation Commission issued an order approving the proposed acquisition of Empire by Liberty Utilities Co. The order approves the Acquisition as filed, without any material conditions.

On September 7, 2016, the Missouri Public Service Commission issued an Order approving the transaction. The Stipulation conditions demonstrate that the transaction is consistent with the approval standard in Missouri.

On September 28, 2016, the Arkansas Public Service Commission ("APSC") approved a joint Stipulation and Settlement Agreement recommending approval of the merger subject to certain conditions which are not considered material.

On October 7, 2016, a stipulation agreement amongst APUC, Empire, and the Kansas Corporation Commission ("KCC") staff was reached and filed with the KCC. A final KCC decision is expected in late 2016, which would allow the transaction to close in early 2017. The statutory time limit for a final KCC decision is January 10, 2017.

Financing Related to the Transaction

On October 25, 2016, the Distribution Group entered into hedges to fix the underlying interest rates for U.S. $500.0 million of the anticipated debt financing in contemplation of closing the Acquisition. The hedges mature on February 13, 2017 and consist of forward purchase contracts of U.S. $250.0 million 10 year U.S. treasuries at approximately1.84% and U.S. $250.0 million 30 year U.S. treasuries at approximately 2.55%.

In order to mitigate the potential effect of foreign exchange rates on the proceeds received from the Convertible Debentures raised in Canadian dollars in contemplation of this acquisition, the Company has converted approximately 73% of the total expected proceeds into U.S. dollars by purchasing spot and forward currency exchange contracts with an average U.S. exchange rate of approximately 1.32. The Company has carried out these transactions over the course of the current year.

See also *Empire District Electric Company Acquisition in Distribution Business Group.*

Dual Listing of Algonquin Common Shares on the New York Stock Exchange

During the quarter, the Company initiated a process to request approval to list its common shares on the New York Stock Exchange ("NYSE"). The Company has been a U.S. Securities and Exchange Commission ("SEC") registrant since 2009. Pending final approval by the NYSE, we anticipate the Company's shares to begin trading on the NYSE within the fourth quarter of 2016. Algonquin will continue to have its shares listed on the Toronto Stock Exchange.

Generation Group Highlights

Completion of the Odell Wind Project

On July 29, 2016, the Odell Wind Facility achieved commercial operation ("COD"). The project consists of a 200 MW wind generating facility located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota. On August 5, 2016, tax equity financing of approximately U.S. $180 million was completed. The Odell Wind Facility is the Generation Group's ninth wind generating facility and consists of 100 Vestas V110 2.0 wind turbines. The facility is expected to generate 831.8 GW-hrs of energy per year, 2.1% higher than initial estimates.

On September 15, 2016, the Company acquired the remaining 50% interest in Odell SponsorCo LLC for U.S $26.5 million and now controls the project.

CRCE Credit at St. Damase

On September 16, 2016, Revenu Québec issued a notice of assessment in regards of the Company's Canadian renewable and conservation expense ("CRCE") refundable tax credit claim for the St. Damase Wind Facility in an amount of $14.3 million. The Company received payment on October 6, 2016.

Distribution Group Highlights

Arizona Rate Case Settlements

Subsequent to the third quarter, the Company received approvals of general rate case settlements from the Arizona Corporate Commission for its Bella Vista Water and Rio Rico Water and Wastewater Systems for combined revenue increases of U.S. $1.9 million effective November 2016. See the "*Regulatory Proceedings*" section for additional details.

2016 Third Quarter Results From Operations

Key Financial Information (all dollar amounts in $ millions except per share information)	**Three Months Ended September 30** **2016**	**2015**
Revenue	**$ 221.3**	$ 189.6
Adjusted EBITDA[1]	**91.4**	70.2
Cash provided by operating activities	**22.6**	76.2
Adjusted Funds from Operations[1]	**61.0**	54.3
Net earnings attributable to shareholders from continuing operations	**17.7**	16.7
Net earnings attributable to shareholders	**17.7**	16.5
Adjusted Net Earnings[1]	**26.6**	17.3
Dividends declared to common shareholders	**37.6**	32.6
Weighted average number of common shares outstanding	**273,202,368**	252,352,179
Per share		
Basic net earnings/(loss) from continuing operations	**$ 0.06**	$ 0.06
Basic net earnings/(loss)	**$ 0.06**	$ 0.05
Adjusted Net Earnings[1,2]	**$ 0.09**	$ 0.06
Diluted net earnings/(loss)	**$ 0.05**	$ 0.05
Cash provided by operating activities[1, 2]	**$ 0.08**	$ 0.32
Adjusted Funds from Operations[1,2]	**$ 0.22**	$ 0.22
Dividends declared to common shareholders	**$ 0.14**	$ 0.13

1 Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings, cash provided by operating activities and Adjusted Funds from Operations to enhance assessment and understanding of the performance of APUC.

The Company's management reporting structure is aligned under three business units: Generation, Distribution, and Transmission Business Groups. At present, the Transmission Group is grouped with Corporate.

For the three months ended September 30, 2016, APUC experienced an average U.S. exchange rate of approximately 1.3047 as compared to 1.3091 in the same period in 2015. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended September 30, 2016, APUC reported total revenue of $221.3 million as compared to $189.6 million during the same period in 2015, an increase of $31.7 million. The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2016 as compared to the corresponding period in 2015 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended September 30
Comparative Prior Period Revenue	**$**	**189.6**
GENERATION GROUP		
Existing Facilities		
Hydro: Increase is primarily due to the receipt of retroactive Global Adjustment payments ($5.4 million) from the Ontario Electricity Financial Corporation ("OEFC") and improved hydrology in the Maritimes, partially offset by lower production in the Quebec region and lower realized rates at two sites in the region with renewed PPAs whose pricing is under negotiation.		6.6
Wind Canada: Decrease is primarily due to the expiry of the Canadian Federal Wind Power Production Incentive ("WPPI") for the St. Leon Wind Facility.		(0.3)
Wind US: Decrease is due to lower market prices and production volumes at existing sites.		(0.5)
Solar Canada: The Cornwall Solar Facility operated consistently with the prior year.		0.1
Solar US: Availability at the Bakersfield I Solar Facility was higher this year due to unscheduled maintenance that occurred in the prior year.		0.6
Thermal: Increase is primarily due to higher REC revenue and production at the Windsor Locks Thermal Facility, partially offset by lower production at the Sanger Thermal Facility.		0.2
Other:		(0.2)
		6.5
New Facilities		
Wind US: The new Odell Wind Facility achieved COD on July 29, 2016 and was consolidated into earnings effective September 15, 2016.		1.4
		1.4
Foreign Exchange		**(0.1)**
DISTRIBUTION GROUP		
Existing Facilities		
Electricity: Increase is primarily related to higher residential demand at the Granite State Electric System as compared to the prior year.		0.3
Gas: Decrease is primarily due to lower demand at the Midstates and New England Gas systems.		(0.7)
Water: Increase is primarily due to higher consumption at the LPSCo and Bella Vista Water Systems.		0.6
Other: Decrease is primarily due to lower revenues for contracted services and the sale of the water heater rental business in the New England Gas System.		(6.1)
		(5.9)
New Facilities		
Water: Increase is due to the acquisition of the Park Water System on January 8, 2016.		28.5
		28.5
Rate Cases		
Electricity: Implementation of interim rates at the Granite State Electric system.		0.8
Gas: Implementation of new rates at the Peach State and New England Gas Systems.		1.0
		1.8
Foreign Exchange		**(0.5)**
Current Period Revenue	**$**	**221.3**

A more detailed discussion of these factors is presented within the business unit analysis.

Adjusted EBITDA in the three months ended September 30, 2016 totalled $91.4 million as compared to $70.2 million during the same period in 2015, an increase of $21.2 million or 30.2%. The increase in Adjusted EBITDA was primarily due to the newly acquired Park Water System, the impact of rate case settlements and increased operating profit from the Hydro facilities. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Performance Measures*).

For the three months ended September 30, 2016, net earnings attributable to shareholders totalled $17.7 million as compared to $16.5 million during the same period in 2015, an increase of $1.2 million or 7.3%. The increase was due to a $21.9 million increase in earnings from operating facilities, $4.6 million increase in gains from derivative instruments, $1.7 million increase in foreign exchange gain, $1.7 million increase in other gains, $1.3 million decrease in net loss on long lived assets, $0.2 million decrease in loss on discontinued operations, and $1.3 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses).* These items were partially offset by a $5.0 million increase in depreciation and amortization expenses, $3.6 million increase in administration charges, $19.4 million increase in interest expense, $1.5 million increase in acquisition costs, $0.8 million decrease in interest and dividend income, and $1.2 million decrease in earnings attributable to non-controlling interests, as compared to the same period in 2015.

During the three months ended September 30, 2016, cash provided by operating activities totalled $22.6 million or $0.08 per share as compared to cash provided by operating activities of $76.2 million or $0.32 per share during the same period in 2015. During the three months ended September 30, 2016, Adjusted Funds from Operations totalled $61.0 million or $0.22 per share as compared to Adjusted Funds from Operations of $54.3 million or $0.22 per share during the same period in 2015. The change in Adjusted Funds from Operations in the three months ended September 30, 2016 is primarily due to increased earnings from operations, as compared to the same period in 2015.

Cash per share provided by operating activities and per share Adjusted Funds from Operations are non-GAAP measures. Per share cash provided by operating activities and per share Adjusted Funds from Operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share Adjusted Funds from Operations do not necessarily represent amounts available for distribution to shareholders.

2016 Year-to-Date Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Nine Months Ended September 30 2016		2015	
Revenue	$	**785.8**	$	767.6
Adjusted EBITDA[1]		**338.6**		266.0
Cash provided by operating activities		**166.0**		167.5
Adjusted Funds from Operations[1]		**260.0**		210.3
Net earnings attributable to shareholders from continuing operations		**84.6**		80.5
Net earnings attributable to shareholders		**84.6**		79.5
Adjusted Net Earnings[1]		**114.0**		82.0
Dividends declared to common shareholders	$	**109.6**	$	90.6
Weighted average number of common shares outstanding		**271,120,426**		251,528,726
Per share				
Basic net earnings	$	**0.28**	$	0.29
Adjusted Net Earnings[1,2]	$	**0.40**	$	0.31
Diluted net earnings	$	**0.28**	$	0.28
Cash provided (used) by operating activities[1,2]	$	**0.63**	$	0.70
Adjusted Funds from Operations[1,2]	$	**0.95**	$	0.85
Dividends declared to common shareholders	$	**0.40**	$	0.36
Total assets		**6,020.8**		4,759.0
Long term debt[3]		**2,380.8**		1,613.3

1 Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings, cash provided by operating activities and Adjusted Funds from Operations to enhance assessment and understanding of the performance of APUC.

3 Includes current and long-term portion of debt and convertible debentures per the financial statements.

For the nine months ended September 30, 2016, APUC experienced an average U.S. exchange rate of approximately $1.3224 as compared to $1.2598 in the same period in 2015. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the nine months ended September 30, 2016, APUC reported total revenue of $785.8 million as compared to $767.6 million during the same period in 2015, an increase of $18.2 million or 2.4%. The major factors resulting in the increase in APUC revenue for the nine months ended September 30, 2016 as compared to the corresponding period in 2015 are set out as follows:

(all dollar amounts in $ millions)		Nine Months Ended September 30
Comparative Prior Period Revenue	**$**	**767.6**
GENERATION GROUP		
Existing Facilities		
Hydro: Increase is primarily due to the receipt of retroactive Global Adjustment payments ($8.4 million) from the OEFC in Ontario and improved hydrology in the Quebec and Maritimes regions.		9.9
Wind Canada: Decrease is due to the expiry of the Canadian Federal WPPI for the St. Leon Wind Facility.		(1.7)
Wind US: Consistent with prior period due to increased wind production at the Minonk Wind Facility offset by lower wind production and related REC revenues at the Sandy, Senate, and Shady Oaks Wind Facilities.		—
Solar Canada: Increase was primarily due to increased production due to improved irradiance as compared to the prior year.		0.3
Thermal: Decrease is primarily due to lower gas prices, which is a pass-through, at the thermal facilities, and reduced demand for steam.		(3.6)
Other:		(0.9)
		4.0
New Facilities		
Wind Canada: Increase is due to the Morse Wind Facility which achieved COD in April 2015.		3.7
Wind US: The new Odell Wind Facility achieved COD on July 29, 2016 and was consolidated into earnings effective September 15, 2016.		1.4
Solar US: Increase is due to the Bakersfield I Solar Facility achieving COD within the provisions of the PPA in April 2015, and greater availability at the facility due to unscheduled maintenance in the prior year.		2.2
		7.3
Foreign Exchange		**6.0**
DISTRIBUTION GROUP		
Existing Facilities		
Electricity: Decrease is primarily due to reduced demand at the Granite State Electric System partially offset by increased residential demand at the Calpeco Electric System.		(13.3)
Gas: Decrease is primarily due to lower demand at the gas utility systems due to warmer winter weather experienced in the year.		(102.5)
Water: Increase is primarily due to higher consumption at the LPSCo and Bella Vista Water Systems.		2.7
Other: Decrease is primarily due to lower revenues for contracted services and the sale of the water heater rental business in the New England Gas System.		(9.3)
		(122.4)
New Facilities		
Water: Increase is due to the acquisition of the Park Water System on January 8, 2016.		75.7
		75.7
Rate Cases		
Gas: Implementation of new rates at the EnergyNorth, Peach State, Illinois and New England Gas Systems.		8.9
Water: Implementation of new rates at the Pine Bluff Water System.		0.2
		9.1
Foreign Exchange		**38.5**
Current Period Revenue	**$**	**785.8**

A more detailed discussion of these factors is presented within the business unit analysis.

Adjusted EBITDA in the nine months ended September 30, 2016 totalled $338.6 million as compared to $266.0 million during the same period in 2015, an increase of $72.6 million or 27.3%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Performance Measures*).

For the nine months ended September 30, 2016, net earnings attributable to shareholders totalled $84.6 million as compared to $79.5 million during the same period in 2015, an increase of $5.1 million. The increase was due to a $70.7 million increase in earnings from operating facilities, $0.7 million increase in gain from derivative instruments, $0.1 million increase in interest and dividend income, $5.5 million increase in Other Gains, $4.2 million increase in gain on long lived assets, $3.1 million increase in losses attributable to non-controlling interests, $1.0 million of decrease in loss on discontinued operations and $6.3 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses).* These items were partially offset by $26.4 million increase in depreciation and amortization expenses, $6.4 million increase in administration charges, $1.1 million decrease in foreign exchange gain, $44.3 million increase in interest expense and $8.3 million increase in acquisition costs as compared to the same period in 2015.

During the nine months ended September 30, 2016, cash provided by operating activities totalled $166 million or $0.63 per share as compared to cash provided by operating activities of $167.5 million, or $0.70 per share during the same period in 2015. During the nine months ended September 30, 2016, Adjusted Funds from Operations, a non-GAAP measure, totalled $260 million or $0.95 per share as compared to Adjusted Funds from Operations of $210.3 million, or $0.85 per share during the same period in 2015, an increase of $49.7 million.

Cash per share provided by operating activities and per share Adjusted Funds from Operations are non-GAAP measures. Per share cash provided by operating activities and per share Adjusted Funds from Operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share Adjusted Funds from Operations do not necessarily represent amounts available for distribution to shareholders.

2016 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Performance Measures*) in the three months ended September 30, 2016 totalled $91.3 million as compared to $70.2 million during the same period in 2015, an increase of $21.1 million or 30.1%. Adjusted EBITDA in the nine months ended September 30, 2016 totalled $338.6 million as compared to $266.0 million during the same period in 2015, an increase of $72.6 million or 27.3%. The breakdown of Adjusted EBITDA by the company's main operating segments and a summary of changes is shown below.

Adjusted EBITDA by segment	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	**2016**	**2015**	**2016**	**2015**
Generation Business Group Operating Profit	**$ 44.8**	$ 35.5	**$ 155.4**	$ 127.0
Distribution Business Group Operating Profit	**58.1**	42.5	**215.6**	165.1
Administrative Expenses	**(12.1)**	(8.5)	**(33.9)**	(27.5)
Other Income & Expenses	**0.5**	0.7	**1.5**	1.4
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 91.3**	$ 70.2	**$ 338.6**	$ 266.0
Change in Adjusted EBITDA ($)	**$ 21.1**		**$ 72.6**	
Change in Adjusted EBITDA (%)	**30.1%**		**27.3%**	

Change in Adjusted EBITDA	Three Months Ended September 30, 2016			
(all dollar amounts in $ millions)	**Generation**	**Distribution**	**Corporate**	**Total**
Prior period balances	**$ 35.5**	**$ 42.5**	**$ (7.8)**	**$ 70.2**
Existing Facilities	6.7	(2.5)	(0.2)	4.0
New Facilities	2.5	16.5	—	19.0
Rate Cases	—	1.8	—	1.8
Foreign Exchange Impact	0.1	(0.2)	—	(0.1)
Administrative Expenses	—	—	(3.6)	(3.6)
Total change during the period	**$ 9.3**	**$ 15.6**	**$ (3.8)**	**$ 21.1**
Current period balances	**$ 44.8**	**$ 58.1**	**$ (11.6)**	**$ 91.3**

Change in Adjusted EBITDA	Nine Months Ended September 30, 2016			
(all dollar amounts in $ millions)	Generation	Distribution	Corporate	Total
Prior period balances	**$ 127.0**	**$ 165.1**	**$ (26.1)**	**$ 266.0**
Existing Facilities	14.8	(7.3)	0.1	7.6
New Facilities	9.6	37.7	—	47.3
Rate cases	—	9.1	—	9.1
Foreign Exchange Impact	4.0	11.0	—	15.0
Administration Expenses	—	—	(6.4)	(6.4)
Total change during the period	**$ 28.4**	**$ 50.5**	**$ (6.3)**	**$ 72.6**
Current period balances	**$ 155.4**	**$ 215.6**	**$ (32.4)**	**$ 338.6**

GENERATION BUSINESS GROUP

2016 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended September 30		Long Term Average Resource	Nine Months Ended September 30	
		2016	2015		2016	2015
Hydro Facilities:						
Maritime Region	**20.7**	**28.0**	20.5	**110.6**	**122.2**	101.4
Quebec Region[1]	**62.3**	**50.2**	61.6	**200.7**	**203.5**	188.1
Ontario Region	**28.5**	**26.4**	30.5	**104.0**	**98.2**	106.4
Western Region	**23.8**	**27.4**	19.7	**52.4**	**48.0**	42.6
	135.3	**132.0**	132.3	**467.7**	**471.9**	438.5
Wind Facilities:						
St. Damase[2]	**16.9**	**15.4**	16.2	**54.2**	**54.0**	52.7
St. Leon	**87.9**	**81.7**	84.9	**308.8**	**286.5**	302.6
Red Lily[3]	**20.4**	**16.5**	17.4	**64.4**	**57.2**	58.1
Morse[4]	**22.6**	**20.2**	18.2	**78.3**	**67.1**	37.3
Sandy Ridge	**29.9**	**23.8**	20.3	**114.7**	**104.0**	106.3
Minonk	**107.6**	**87.4**	91.7	**478.5**	**450.9**	424.7
Senate	**91.7**	**102.4**	103.7	**380.4**	**367.7**	332.9
Shady Oaks	**53.2**	**47.9**	51.6	**264.3**	**219.5**	228.1
Odell[5]	**110.7**	**86.5**	—	**110.7**	**86.5**	—
	540.9	**481.8**	404.0	**1,854.3**	**1,693.4**	1,542.7
Solar Facilities:						
Cornwall	**4.8**	**5.4**	5.1	**12.5**	**13.7**	12.9
Bakersfield I[6]	**17.0**	**15.9**	11.8	**43.9**	**38.5**	26.3
	21.8	**21.3**	16.9	**56.4**	**52.2**	39.2
Renewable Energy Performance	**698.0**	**635.1**	553.2	**2,378.4**	**2,217.5**	2,020.4
Thermal Facilities:						
Windsor Locks	**N/A[7]**	**45.0**	30.7	**N/A[7]**	**100.1**	88.2
Sanger	**N/A[7]**	**32.0**	36.6	**N/A[7]**	**89.9**	97.4
		77.0	67.3		**190.0**	185.6
Total Performance		**712.1**	620.5		**2,407.5**	2,206.0

[1] The Generation Group's 4.8 MW Donnacona Hydro Facility has been offline since May 2015. Reconstruction of the Donnacona Dam has commenced.

[2] The quarterly timing of the long term average resource for St. Damase has been adjusted based on the first full year of operation. The annual value is unchanged.

[3] Effective April 12, 2016, APUC, through its subsidiary, exercised its option and acquired a 75% equity interest in the facility. For financial accounting purposes, APUC's majority interest in the Red Lily Wind Facility will be accounted for using the equity method. The production figures represent full energy produced by the facility.

[4] The Morse Wind Facility achieved commercial operation on April 22, 2015.

[5] The Odell Wind Facility achieved commercial operation on July 29, 2016 and was treated as an equity investment until September 15, 2016 at which time the Company acquired the remaining 50% ownership in the facility. The LTAR and production noted above represents all production from the date of COD.

[6] The Bakersfield I Solar Facility achieved commercial operation on April 14, 2015 in accordance with the terms of the PPA.

[7] Natural gas fired co-generation facility.

2016 Third Quarter Generation Performance

For the three months ended September 30, 2016, the Generation Group generated 712.1 GW-hrs of electricity as compared to 620.5 GW-hrs during the same period of 2015.

For the three months ended September 30, 2016, the hydro facilities generated 132.0 GW-hrs of electricity, as compared to 132.3 GW-hrs produced in the same period in 2015, a decrease of 0.2%. Electricity generated represented 97.6% of long-term average resources ("LTAR") as compared to 97.8% during the same period in 2015. In the quarter, increased generation in the Maritimes and Western regions offset declines in Quebec and Ontario.

For the three months ended September 30, 2016, the wind facilities produced 481.8 GW-hrs of electricity, as compared to 404.0 GW-hrs produced in the same period in 2015, an increase of 19.3%. The higher generation was primarily due to the Odell Wind Facility achieving commercial operation ("COD") on July 29, 2016. This was partly offset by lower production at the Minonk, Shady Oaks and St. Leon Wind Facilities. During the three months ended September 30, 2016, the wind facilities (excluding the Odell Wind Facility) generated electricity equal to 91.9% of LTAR as compared to 94.0% during the same period in 2015.

For the three months ended September 30, 2016, the solar facilities generated 21.3 GW-hrs of electricity as compared to 16.9 GW-hrs of electricity in the same period in 2015, an increase of 26.0%. The increase in production is largely attributable to the Bakersfield I Solar Facility which was negatively impacted by unscheduled maintenance in the prior year. Cornwall's production was 12.5% above its LTAR as compared to 6.3% above its LTAR in the same period in 2015.

For the three months ended September 30, 2016, the thermal facilities generated 77.0 GW-hrs of electricity as compared to 67.3 GW-hrs of electricity during the same period in 2015. During the same period, the Windsor Locks Thermal Facility generated 103.9 billion lbs of steam, as compared to 121.1 billion lbs of steam during the same period in 2015.

2016 Year-to-Date Generation Performance

For the nine months ended September 30, 2016, the Generation Group generated 2,407.5 GW-hrs of electricity as compared to 2,206.0 GW-hrs during 2015.

For the nine months ended September 30, 2016, the hydro facilities generated 471.9 GW-hrs of electricity as compared to 438.5 GW-hrs produced in the same period in 2015, an increase of 7.6%. Electricity generated represented 100.9% of long-term projected average resources as compared to 93.8% during the same period in 2015. During the nine months ended September 30, 2016, the Quebec and Maritimes Hydro regions achieved production above their LTAR, while the Western and Ontario regions were below their respective LTAR. The Quebec region was above its LTAR despite the Donnacona Hydro Facility being offline during the period.

For the nine months ended September 30, 2016, the wind facilities produced 1,693.4 GW-hrs of electricity as compared to 1,542.7 GW-hrs produced in the same period in 2015, an increase of 9.8%. During the nine months ended September 30, 2016, the wind facilities generated electricity equal to 91.3% of LTAR, as compared to 90.3% during the same period in 2015. The increase in production was primarily due to higher production at the Minonk and Senate Wind Facilities, as well as the incremental electricity generated at the Morse and Odell Wind Facilities which achieved commercial operation on April 22, 2015 and July 29, 2016 respectively.

For the nine months ended September 30, 2016, the solar facilities generated 52.2 GW-hrs of electricity as compared to 39.2 GW-hrs of electricity produced in the same period in 2015, an increase of 33.2%. The increase in production is attributable to the new Bakersfield I Solar Facility which achieved COD on April 14, 2015. The Cornwall Solar Facility's production was 9.6% above its LTAR as compared to 3.2% above its LTAR in the same period last year. The Bakersfield I Solar Facility's production was 12.3% below its LTAR due to unscheduled maintenance.

For the nine months ended September 30, 2016, the thermal facilities generated 190.0 GW-hrs of electricity as compared to 185.6 GW-hrs of electricity during the same period in 2015. During the same period, the Windsor Locks Thermal Facility generated 423.2 billion lbs of steam as compared to 458.0 billion lbs of steam during the same period in 2015.

2016 Generation Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended September 30 2016	Three Months Ended September 30 2015	Nine Months Ended September 30 2016	Nine Months Ended September 30 2015
Revenue[1]				
Hydro	**$ 17.9**	$ 11.4	**$ 51.9**	$ 41.1
Wind	**22.8**	22.7	**85.6**	79.6
Solar	**4.7**	4.0	**11.3**	8.6
Thermal	**10.9**	11.3	**27.3**	30.2
Total Revenue	**$ 56.3**	$ 49.4	**$ 176.1**	$ 159.5
Less:				
Cost of Sales - Energy[2]	**(1.6)**	(1.5)	**(3.9)**	(8.6)
Cost of Sales - Thermal	**(4.4)**	(3.7)	**(11.1)**	(14.0)
Realized gain/(loss) on hedges[3]	**—**	—	**(0.9)**	0.6
Net Energy Sales[5]	**$ 50.3**	$ 44.2	**$ 160.2**	$ 137.5
Renewable Energy Credits ("REC")[4]	**3.6**	2.5	**13.9**	12.6
Other Revenue	**0.6**	0.6	**1.9**	1.7
Total Net Revenue	**$ 54.5**	$ 47.3	**$ 176.0**	$ 151.8
Expenses & Other Income				
Operating expenses	**(17.4)**	(17.0)	**(52.2)**	(48.6)
Interest, dividend, equity and other income	**1.4**	—	**1.4**	0.3
Operating Profit from non-Consolidated entities[5]	**1.1**	0.7	**2.8**	2.1
HLBV income[6]	**5.2**	4.5	**27.4**	21.4
Divisional Operating Profit[7,8]	**$ 44.8**	$ 35.5	**$ 155.4**	$ 127.0

1 While most of the Generation Group's PPAs include annual rate increases, a change to the weighted average production levels resulting from higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division as compared to the same period in the prior year.

2 Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Facility which is sold to retail and industrial customers under multi-year contracts.

3 See financial statements note 21(b)(iv).

4 Qualifying renewable energy projects receive Renewable Energy Credits ("REC") for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The REC can be traded and the owner of the REC can claim to have purchases of renewable energy. REC revenue is recognized only at the time a generated REC unit is matched up with a previously signed REC sales contract with a third party. Generated REC units not immediately available to match against a signed contract are recorded as inventory, with the offset recorded as a decrease in operating expenses.

5 When the Generation Business Group manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculation of divisional operating profit. Certain figures recorded in accordance with GAAP have been adjusted to conform to this presentation.

6 Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

7 Certain prior year items have been reclassified to conform with current year presentation

8 See Non-GAAP Financial Measures.

2016 Third Quarter Operating Results

For the three months ended September 30, 2016, the Generation Group facilities generated $44.8 million of operating profit as compared to $35.5 million during the same period in 2015, which represents an increase of $9.3 million, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended September 30	
Prior Period Operating Profit	**$**	**35.5**
Existing Facilities		
Hydro: Increase is primarily due to the receipt of retroactive Global Adjustment payments ($5.4 million) from the OEFC and improved hydrology in the Maritimes, partially offset by lower production and lower rates at two facilities in the Quebec region.		6.6
Wind Canada: Decrease is primarily due to the expiry of the Canadian Federal WPPI for the St. Leon Wind Facility.		(0.3)
Wind US: Decrease is primarily due to annual increases in costs related to O&M contracts, insurance and property tax.		(1.1)
Solar Canada: Increase is primarily due to lower operating costs compared to the previous year.		0.3
Solar US: Increase is due to higher production and HLBV income at the Bakersfield I Solar Facility as compared to the same period in the prior year.		1.4
Thermal: Decrease is due to lower production and increased gas prices at the Sanger Thermal Facility.		(0.6)
Other: Increase is primarily due to interest income earned on the OEFC's Global Adjustment payments.		0.4
		6.7
New Facilities		
Wind Canada: Incremental operating profit from the purchase of the Red Lily Wind Facility.		1.0
Wind US: The new Odell Wind Facility achieved COD on July 29, 2016 and was consolidated into earnings effective September 15, 2016.		1.5
		2.5
Foreign Exchange		**0.1**
Current Period Divisional Operating Profit	**$**	**44.8**

2016 Year-to-Date Operating Results

For the nine months ended September 30, 2016, the Generation Group facilities generated $155.4 million of operating profit as compared to $127.0 million during the same period in 2015, which represents an increase of $28.4 million or 22.4%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Nine Months Ended September 30
Prior Period Operating Profit	**$**	**127.0**
Existing Facilities		
Hydro: Increase is primarily due to the receipt of retroactive Global Adjustment payments ($8.4 million) from the OEFC and improved hydrology in the Quebec and Maritime regions.		13.8
Wind Canada: Decrease is primarily due to the expiry of Canadian Federal WPPI for the St. Leon Wind Facility.		(1.8)
Wind US: Increase is primarily due to higher HLBV income due to the reduced economic interest of Tax Equity investors partially offset by lower production at the Shady Oaks Facility.		2.6
Solar Canada: Increase is primarily due to higher production as a result of improved irradiance, compared to the same period in the prior year.		0.4
Thermal: The decrease was primarily due to reduced customer demand at the Sanger Thermal Facility.		(0.5)
Other: Increase is primarily due to interest income earned on Global Adjustment payments.		0.3
		14.8
New Facilities		
Wind Canada: The Morse Wind Facility achieved COD on April 22, 2015.		3.3
Wind Canada: Incremental operating profit from the purchase of the Red Lily Wind Facility.		1.2
Wind US: The new Odell Wind Facility achieved COD on July 29, 2016, and was consolidated into earnings effective September 15, 2016.		1.5
Solar US: The Bakersfield I Solar Facility achieved COD in accordance with its PPA on April 14, 2015.		3.6
		9.6
Foreign Exchange		**4.0**
Current Period Divisional Operating Profit	**$**	**155.4**

GENERATION BUSINESS GROUP

Development Division

The Development Division works to identify, develop and construct new power generating facilities as well as to identify and acquire operating projects that would be complementary and accretive to the Generation Group's existing portfolio.

The Generation Group's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with credit-worthy counterparties, and meet or exceed the Company's investment return criteria.

Project Name	Location	Size (MW)		Estimated Capital Cost (millions)[5]	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction							
Bakersfield II Solar Project[1]	California	10	$	35.4	2016	20	24.2
Deerfield Wind Project[2]	Michigan	150		397.4	2016/17	20	555.2
Total Projects in Construction		**160**	**$**	**432.8**			**579.4**
Projects in Development							
Amherst Island Wind Project	Ontario	75	$	272.5	2018	20	235.0
Chaplin Wind Project	Saskatchewan	177		340.0	2019/20	25	720.0
Great Bay Solar Project[3]	Maryland	75		236.1	2017	10	152.0
Val-Eo Wind Project[4]	Quebec	24		70.0	2017/18	20	66.0
Total Projects in Development		**351**	**$**	**918.6**			**1,173.0**
Total in Construction and Development		**511**	**$**	**1,351.4**			**1,752.4**

1 Total cost of the project is expected to be approximately $27 million in U.S. dollars.

2 Total cost of the project is expected to be approximately $303 million in U.S. dollars.

3 The total cost of the project is expected to be approximately $180 million in U.S. dollars.

4 All figures refer solely to Phase I of the Val-Eo Wind Project.

5 U.S.$ amounts converted at the exchange rate in effect at the end of the current reporting period

Projects in Construction or Recently Completed

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MWac solar powered electric generating project adjacent to the Generation Group's 20 MWac Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. As of September 30, 2016, all modules, trackers, and inverters have been installed and the substation has been successfully interconnected and back fed by the off-taker. Mechanical completion was achieved in September 2016, and the project has a commercial operation date targeted before the end of 2016. Closing of the tax equity investment is expected to occur shortly thereafter.

Deerfield Wind Project

The Deerfield Wind Project is a 150 MW wind powered electric generating development project located in central Michigan and is being constructed on approximately 20,000 acres of leased land.

Construction of the project commenced in the fourth quarter of 2015. As of the date of this MD&A, all private land access roads have been constructed, all foundations have been installed, and all 72 turbines have been erected. The project has a commercial operation date targeted for the fourth quarter of 2016 or early 2017.

Projects in Development

Amherst Island Wind Project

The Amherst Island Wind Project is a 75 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario. The 75 MW project was awarded a Feed-In-Tariff ("FIT") contract by the OPA as part of the second round of the OPA's FIT program.

The Renewable Energy Approval ("REA") was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment. An appeal of the REA was made to the Environmental Review Tribunal ("ERT") in 2015. The ERT decision to uphold the REA was issued on August 3, 2016. The project is now moving to the final development and construction stage.

Since the REA decision, Algonquin has moved ahead with procurement and construction contracting for the facility. The project has now procured the project turbines, submarine cable, and the main power transformer. Negotiations are in progress for the balance of plant constructor. Subject to receipt of final permits and negotiation of remaining agreements, final development and construction is expected to take approximately 18 months.

Chaplin Wind Project

The Chaplin Wind Project is a 177 MW wind powered electric generating development being developed in Saskatchewan.

The project will be developed in two phases: Phase I of the project is expected to represent approximately 35 MW of the total project, with all energy from Phase I of the project sold to SaskPower pursuant to a 25 year PPA and Phase II of the project, which comprises the remaining approximately 142 MW, will be the infill construction phase and will only proceed following the successful evaluation of the wind resource at the site. Both phases require the completion of the necessary permitting.

The Saskatchewan Ministry of the Environment has determined the original proposed location for the project does not meet its new siting guidelines for wind farms. As a result SaskPower and Algonquin have worked to reconfigure the project in a manner that meets new siting guidelines for wind farms in Saskatchewan.

Great Bay Solar

The Great Bay Solar Project is a 75 MWac solar powered electric generating development project located in Somerset County in southern Maryland.

Permitting with the county is underway and is expected to be completed in the fourth quarter of 2016. The project has received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission. The EPC contract has been executed, and equipment procurement is in progress. The project has a commercial operations date targeted for 2017.

Val-Éo Wind Project

The Val-Éo Wind Project is a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec. The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Generation Group.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2017/18 and will likely be comprised of ten 2.35 MW wind turbines and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project sold to Hydro Quebec pursuant to a 20 year PPA and Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

All land agreements, construction permits, and authorizations have been obtained for Phase I. The new schedule calls for Phase 1 construction to begin in the spring of 2017, with commissioning to occur in 2017/2018.

DISTRIBUTION BUSINESS GROUP

The Distribution Group operates rate-regulated utilities that provide distribution services to approximately 564,000 connections in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type

	As at September 30					
	2016			2015		
(all dollar amounts in U.S. $ millions)		Assets	Total Connections[1]		Assets	Total Connections[1]
Electricity	$	**362.9**	**93,000**	$	338.1	93,000
Natural Gas		**816.9**	**293,000**		763.2	292,000
Water and Wastewater		**503.0**	**178,000**		255.8	103,000
Total	$	**1,682.8**	**564,000**	$	1,357.1	488,000
Accumulated Deferred Income Taxes	$	**172.4**		$	100.9	

[1] Total Connections represents the sum of all active and vacant connections.

The Distribution Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 93,000 connections in the states of California and New Hampshire.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 293,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 178,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri, Montana, and Texas. California and Montana were added during the first quarter of 2016 in connection with the closing of the acquisition of the Park Water System.

2016 Third Quarter Usage Results

Electric Distribution Systems

	Three Months Ended September 30	
	2016	2015
Average Active Electric Connections For The Period		
Residential	80,400	79,800
Commercial and industrial	12,400	12,400
Total Average Active Electric Connections For The Period	**92,800**	**92,200**
Customer Usage (GW-hrs)		
Residential	136.8	132.2
Commercial and industrial	235.2	237.5
Total Customer Usage (GW-hrs)	**372.0**	**369.7**

For the three months ended September 30, 2016 the electric distribution systems' usage totalled 372.0 GW-hrs as compared to 369.7 GW-hrs for the same period in 2015, an increase of 2.3 GW-hrs.

Natural Gas Distribution Systems

	Three Months Ended September 30	
	2016	**2015**
Average Active Natural Gas Connections For The Period		
Residential	245,600	244,400
Commercial and industrial	26,000	26,100
Total Average Active Natural Gas Connections For The Period	**271,600**	**270,500**
Customer Usage (MMBTU)		
Residential	963,000	986,000
Commercial and industrial	1,276,000	1,402,000
Total Customer Usage (MMBTU)	**2,239,000**	**2,388,000**

For the three months ended September 30, 2016, usage at the natural gas distribution systems totalled 2,239,000 MMBTU as compared to 2,388,000 MMBTU during the same period in 2015, a decrease of 149,000 MMBTU, or 6.2%. The impact of heating degree days on customer usage is less significant in the warmer three months ended September 30, 2016 as compared to the colder winter months.

Water and Wastewater Distribution Systems

	Three Months Ended September 30	
	2016	**2015**
Average Active Connections For The Period		
Wastewater connections	40,400	40,000
Water distribution connections	131,200	58,700
Total Average Active Connections For The Period	**171,600**	**98,700**
Gallons Provided		
Wastewater treated (millions of gallons)	529	497
Water sold (millions of gallons)	6,102	2,478
Total Gallons Provided	**6,631**	**2,975**

During the three months ended September 30, 2016, the water and wastewater distribution systems provided approximately 6,102 million gallons of water to its customers and treated approximately 529 million gallons of wastewater as compared to 2,478 million gallons of water provided and 497 million gallons of wastewater treated during the same period in 2015. The increase in the gallons of water provided to customers can be primarily attributed to the addition of the Park Water System on January 8, 2016. The Park Water system provided approximately 3,570 million gallons of water to customers during the three months ended September 30, 2016.

2016 Third Quarter Operating Results - Distribution Group

	Three Months Ended September 30			
	2016 U.S. $ (millions)	**2015 U.S. $ (millions)**	**2016 Can $ (millions)**	**2015 Can $ (millions)**
Revenue				
Utility electricity sales and distribution	**$ 41.6**	$ 40.8	**$ 54.2**	$ 53.4
Less: cost of sales – electricity	**(21.7)**	(22.4)	**(28.4)**	(29.3)
Net Utility Sales - electricity	**19.9**	18.4	**25.8**	24.1
Utility natural gas sales and distribution	**34.2**	34.2	**44.7**	44.6
Less: cost of sales – natural gas	**(7.1)**	(7.4)	**(9.3)**	(10.0)
Net Utility Sales - natural gas	**27.1**	26.8	**35.4**	34.6
Utility water distribution & wastewater treatment sales and distribution	**39.1**	16.8	**51.0**	21.9
Less: cost of sales – water	**(2.7)**	—	**(3.5)**	—
Net Utility Sales - water distribution & wastewater treatment	**36.4**	16.8	**47.5**	21.9
Gas transportation	**3.6**	3.6	**4.7**	4.7
Other revenue	**4.5**	9.1	**6.0**	12.1
Net Utility Sales	**91.5**	74.7	**119.4**	97.4
Operating expenses	**(48.0)**	(42.7)	**(62.6)**	(55.9)
Other income	**1.0**	0.7	**1.3**	1.0
Divisional Operating Profit[1]	**$ 44.5**	$ 32.7	**$ 58.1**	$ 42.5

1 Certain prior year items have been reclassified to conform with current year presentation

For the three months ended September 30, 2016, the Distribution Group reported an operating profit (excluding corporate administration expenses) of U.S. $44.5 million as compared to U.S. $32.7 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was $58.1 million as compared to $42.5 million during the same period in 2015, which represents an increase of $15.6 million, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended September 30
Prior Period Operating Profit	**$ 42.5**
Existing Facilities	
Electricity: Increase is primarily due to lower operating expenses at the Granite State Electric System.	0.9
Gas: Increase is primarily due to lower operating expenses at the EnergyNorth, Peach State and New England Gas systems.	1.5
Water: Increase primarily related to higher consumption at the LPSCo and Bella Vista Water systems.	0.8
Other: Decrease primarily due to lower revenues for contracted services.	(5.7)
	(2.5)
New Facilities	
Water: Increase due to the acquisition of the Park Water System.	16.5
	16.5
Rate Cases	
Electric: Increase due to implementation of interim rates at the Granite State Electric system.	0.8
Gas: Increase due to the application of new rates at the Peach State and New England Gas systems.	1.0
	1.8
Foreign Exchange	**(0.2)**
Current Period Divisional Operating Profit	**$ 58.1**

2016 Year-To-Date Usage Results

Electric Distribution Systems

	Nine Months Ended September 30	
	2016	**2015**
Average Active Electric Connections For The Period		
Residential	80,300	79,800
Commercial and industrial	12,400	12,400
Total Average Active Electric Connections For The Period	**92,700**	**92,200**
Customer Usage (GW-hrs)		
Residential	424.5	419.2
Commercial and industrial	670.2	678.3
Total Customer Usage (GW-hrs)	**1,094.7**	**1,097.5**

For the nine months ended September 30, 2016 the electric distribution systems' usage totalled 1,094.7 GW-hrs as compared to 1,097.5 GW-hrs for the same period in 2015, a decrease of 2.8 GW-hrs. Customer usage at the Granite State Electric system decreased by approximately 30.1 GW-hrs due to warmer weather experienced in the region as compared to the prior year. This decrease was mostly offset by increased customer usage at the CalPeco Electric System which was 27.3 GW-hrs higher as compared to the prior year.

Natural Gas Distribution Systems

	Nine Months Ended September 30	
	2016	**2015**
Average Active Natural Gas Connections For The Period		
Residential	249,300	248,500
Commercial and Industrial	26,500	26,700
Total Average Active Natural Gas Connections For The Period	**275,800**	**275,200**
Customer Usage (MMBTU)		
Residential	11,610,000	14,382,000
Commercial and Industrial	7,915,000	10,098,000
Total Customer Usage (MMBTU)	**19,525,000**	**24,480,000**

For the nine months ended September 30, 2016, usage at the natural gas distribution systems totalled 19,525,000 MMBTU as compared to 24,480,000 MMBTU during the same period in 2015, a decrease of 4,955,000 MMBTU or 20.2%. The decrease in natural gas usage as compared to the same period in 2015, can be primarily attributed to a decrease in heating degrees days experienced at the EnergyNorth, Midstates and New England Gas Systems service territories.

Water and Wastewater Distribution Systems

	Nine Months Ended September 30	
	2016	**2015**
Average Active Connections For The Period		
Wastewater connections	41,400	40,000
Water distribution connections	132,500	58,700
Total Average Active Connections For The Period	**173,900**	98,700
Gallons Provided		
Wastewater treated (millions of gallons)	1,688	1,636
Water sold (millions of gallons)	13,823	6,486
Total Gallons Provided	**15,511**	8,122

During the nine months ended September 30, 2016, the water and wastewater distribution systems provided approximately 13,823 million gallons of water to its customers and treated approximately 1,688 million gallons of wastewater as compared to 6,486 million gallons of water and 1,636 million gallons of wastewater during the same period in 2015. The increase in water provided can be primarily attributed to the acquisition of the Park Water System on January 8, 2016 which provided 7,471 million gallons of water during the year.

2016 Year-To-Date Operating Results - Distribution Group

	Nine Months Ended September 30			
	2016 U.S. $ (millions)	**2015 U.S. $ (millions)**	**2016 Can $ (millions)**	**2015 Can $ (millions)**
Revenue				
Utility electricity sales and distribution	**$ 124.8**	$ 134.8	**$ 165.5**	$ 169.5
Less: cost of sales – electricity	**(69.4)**	(80.2)	**(92.3)**	(100.7)
Net Utility Sales - electricity	**55.4**	54.6	**73.2**	68.8
Utility natural gas sales and distribution	**192.7**	259.5	**258.7**	323.6
Less: cost of sales – natural gas	**(65.2)**	(135.6)	**(88.9)**	(168.3)
Net Utility Sales - natural gas	**127.5**	123.9	**169.8**	155.3
Utility water distribution & wastewater treatment sales and distribution	**105.7**	46.0	**139.4**	58.1
Less: cost of sales – water	**(7.0)**	—	**(9.2)**	—
Net Utility Sales - water distribution & wastewater treatment	**98.7**	46.0	**130.2**	58.1
Gas transportation	**17.3**	20.7	**23.6**	25.9
Other revenue	**5.0**	12.0	**6.5**	15.6
Net Utility Sales	**303.9**	257.2	**403.3**	323.7
Operating expenses	**(144.8)**	(128.1)	**(191.6)**	(161.5)
Other income	**2.9**	2.3	**3.9**	2.9
Divisional Operating Profit[1]	**$ 162.0**	$ 131.4	**$ 215.6**	$ 165.1

[1] Certain prior year items have been reclassified to conform with current year presentation

For the nine months ended September 30, 2016, the Distribution Group reported an operating profit (excluding corporate administration expenses) of U.S. $162.0 million as compared to U.S. $131.4 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was $215.6 million as compared to $165.1 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Nine Months Ended September 30
Prior Period Operating Profit	**$ 165.1**
Existing Facilities	
Electricity: Increase is primarily due to higher demand at the Calpeco Electric System and increased cost controls at the Granite State Electric System partially offset by higher operating costs at the Calpeco Electric System.	1.6
Gas: Decrease is primarily due to a one-time U.S. $3.0 million recoupment of revenue that occurred in the second quarter of 2015 at the EnergyNorth Gas System as permitted pursuant to its 2014 rate case, as well as lower demand at the gas systems due to warmer winter weather resulting in lower heating degree days.	(3.9)
Water: Increase primarily related to higher demand at the LPSCo and Bella Vista Water Systems.	3.2
Other: Decrease primarily due to lower revenues for contracted services and the sale of the water heater rental business in the New England Gas System.	(8.2)
	(7.3)
New Facilities	
Water: Increase due to the acquisition of the Park Water System	37.7
	37.7
Rate Cases	
Gas: Implementation of new rates at the EnergyNorth, Peach State, Illinois and New England Gas systems.	8.9
Water: Implementation of new rates at the Pine Bluff Water System.	0.2
	9.1
Foreign Exchange	**11.0**
Current Period Divisional Operating Profit	**$ 215.6**

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Distribution Group:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Rio Rico Water/ Sewer System	Arizona	General Rate Case	$0.9	Application filed in October 2015 seeking a U.S. $0.9 million revenue increase. A final permanent rate decision issued in October 2016 allowed for a $0.97 million revenue increase effective Nov 2016.
Bella Vista Water System	Arizona	General Rate Case	$1.6	Application filed in October 2015 seeking a U.S. $1.6 million revenue increase. A final permanent rate decision issued in October 2016 allowed for a $0.96 million revenue increase effective Nov 2016.
Pending Rate Cases				
CalPeco Electric System	California	General Rate Case	$13.6	Application filed in May 2015 seeking a U.S. $13.6 million revenue increase (U.S. $11.4 million related directly to distribution margin) effective January 2016. A settlement agreement was reached in April 2016 allowing a U.S. $9.8 million distribution margin revenue increase retroactive to Q1 2016. A final permanent rate decision is expected in Q4 2016.
Entrada Del Oro	Arizona	General Rate Case	$0.3	Application filed in March 2016 seeking a U.S. $0.3 million revenue increase. A final permanent rate decision is expected in Q2 2017.
Granite State Electric System	New Hampshire	General Rate Case	$7.7	Application filed in April 2016 seeking a U.S. $7.7 million revenue increase. A temporary rate increase of U.S. $2.4 million became effective July 2016. A final permanent rate decision is expected in Q2 2017.
Illinois Gas System	Illinois	General Rate Case	$3.0	Application filed in July 2016 seeking a U.S. $3.0 million revenue increase. A final permanent rate decision is expected in Q2 2017.
Iowa Gas System	Iowa	General Rate Case	$1.1	Application filed in July 2016 seeking a U.S. $1.1 million revenue increase. A final permanent rate decision is expected in Q2 2017.
Woodmark/Tall Timbers Water & Wastewater Systems	Texas	General Rate Case	$2.0	Application filed in September 2016 seeking a U.S. $2.0 million revenue increase. A final permanent rate decision is expected in Q4 2017.
Peach State Gas System	Georgia	GRAM	$0.6	Application filed in October 2016 seeking a U.S. $0.6 million revenue increase. A final permanent rate decision is expected in Q4 2016, with new rates effective February 2017.

Completed Rate Cases

On October 28, 2015, the Rio Rico Water and Wastewater System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, a 10.8% return on equity ("ROE") and 70% equity. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case sought to recover increased operating costs and capital improvements. The rate case also sought approval for the fair value Arizona rate evaluation model ("FARE"), a purchased power adjuster mechanism ("PPAM") and a property tax adjuster mechanism ("PTAM"). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.97 million revenue increase. A Recommended Opinion and Order ("ROO") was issued in October 2016 accepting the settlement. A final decision was issued on October 27, 2016 approving the settlement, with implementation of new rates in November 2016. Its previous rate case was based on a test year ending February 2012.

On October 28, 2015, the Bella Vista Water System filed a rate case and financing application. The application sought an increase in revenue requirement of U.S. $1.6 million, or 33.6%, based on a test year ending December 31, 2014, a rate base of U.S. $13.2 million, 11.6% ROE, and 70% equity. This rate case seeks to recover increased operating costs and capital improvements. It also includes approval for the FARE, a PPAM and a PTAM. A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.96 million revenue increase. A ROO was issued in October 2016 accepting the settlement. A final decision was issued on October 27, 2016 approving the settlement, with implementation of new rates in November 2016. Its previous rate case was based on a test year ending March 2009.

Pending Rate Cases and Other Regulatory Applications

On May 1, 2015, the CalPeco Electric System filed an application with the CPUC seeking an increase in revenue of U.S. $13.6 million (of which U.S. $11.4 million related to an increase in distribution margin revenue, and the remainder related to energy costs and other non-distribution charges), or 17.3%, based on a test year ending December 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The increase reflects a requested 10.5% ROE, and 55% equity. The previous test year ended December 31, 2011. In May 2016, an all-party settlement was filed with the CPUC allowing for a U.S. $9.8 million net distribution margin revenue increase, or approximately 86% of the requested increase. The increase reflects a 10.0% ROE and 52.5% equity. A final permanent rate decision from the CPUC is expected to approve the settlement in the fourth quarter of 2016, however, new permanent rates will be retroactively effective in the first quarter of 2016.

On March 3, 2016, the Entrada Del Oro Wastewater System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $0.3 million, or 90.5%, based on a test year ending October 31, 2015, a rate base of U.S. $2.2 million, 12% ROE, and 70% equity. Rates are proposed to be phased in over two years due to the magnitude of the increase. This rate case seeks to recover increased operating costs and capital improvements. A final decision and implementation of new rates is expected for the second quarter of 2017. Its previous rates became effective July 2006.

On April 29, 2016, the Granite State Electric System filed a rate application. The application seeks a U.S. $5.3 million annual revenue increase proposed for effect July 1, 2016, or a 15.0% increase to distribution revenue, plus an additional U.S. $2.4 million annual increase (step increase) to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase being proposed is U.S. $7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. $2.4 million was issued, effective July 1, 2016. The final permanent revenue increase will be retroactive to the temporary rate effective date. The step increase would become effective at the time permanent rates become effective following the close of the proceeding. A Final Order is expected in the second quarter of 2017.

On July 25, 2016, the Illinois Gas System filed a rate application. The application seeks a U.S. $3.0 million annual revenue increase to a proposed revenue requirement of U.S. $15.3 million, or a 24% increase, based on a 2017 projected test year. Proposals include a10.3% ROE, 54% equity, 4.83% cost of debt, 7.8% WACC, and a U.S. $45.0 million rate base. A Final Order is expected in May 2017. Its previous rate case was filed in March 2014 and was based on a 2015 projected test year.

On July 25, 2016, the Iowa Gas System filed a rate application. The application seeks a U.S. $1.1 million annual revenue increase to a proposed revenue requirement of U.S. $3.2 million, or a 46% increase, based on a 2015 historical test year with pro-forma changes to June 2016. Proposals include a 10.25% ROE, 54% equity, 4.8% cost of debt, 7.76% WACC, and a U.S. $6.5 million rate base. Interim rates became effective August 4, 2016, allowing an interim revenue increase of U.S. $0.5 million on an annualized basis, or 50% of total proposed increase. A Final Order is expected in May 2017. Its previous rate case took place in 2001.

On September 2, 2016, the Woodmark and Tall Timbers Wastewater Systems filed a rate application with the Texas Public Utilities Commission. The application seeks a combined, phased-in U.S. $2.0 million annual revenue increase to a proposed revenue requirement of U.S. $4.7 million, or a 71.0% increase, based on a 2015 historical test year with pro-forma adjustments. Proposals include a 10.2% ROE, 70.0% equity, 4.95% cost of debt, 8.6% WACC, and a combined U.S. $11.9 million rate base. The proposed increase consists of two steps with the initial increase of U.S. $1.0 million based on the historical 2015 test year, and a second step of U.S. $1.0 million to recognize the incremental rate base associated with investments in the Woodmark treatment plant expansion and a Tall Timbers line relocation beyond the historical test year. A Final Order is expected in the fourth quarter of 2017.

On October 1, 2016, the Georgia Gas System filed its annual Georgia Rate Adjustment Mechanism (GRAM). The application seeks a U.S. $0.6 million annual revenue increase to a proposed revenue requirement of U.S. $31.3 million, or a 1.9% increase, based on test year ending June 2016. The GRAM proposals include a 10.5% ROE, 55.0% equity, and a U.S. $99.0 million rate base. A Final Order is expected to allow for implementation of new rates in February 2017.

Other Applications filed in the Third Quarter

On April 15, 2016, the EnergyNorth Gas System filed with the NHPUC a proposed distribution rate increase of 0.1% based on an annual revenue requirement increase of U.S. $0.2 million related to the Cast Iron Bare Steel ("CIBS") program. An Order was issued July 2016, with effect the same day, approving an increase of U.S. $0.2 million.

On February 15, 2016, the Georgia Gas System filed with the Georgia PSC a proposed distribution revenue decrease of U.S. $0.3 million, based on an annual revenue requirement of U.S. $7.6 million related to its Pipeline Replacement Program ("PRP"). The proposed PRP rate base is U.S. $60.4 million. An Order was issued September 2016 approving the application, with new rates effective October 2016.

Park Water System Acquisition

On January 8, 2016, the Distribution Group completed the acquisition of Western Water Holdings, a company which through its subsidiaries owns three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains. Mountain Water Company is the water utility in Western Montana serving the municipality of Missoula owned by Park Water Company.

Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. On August 2, 2016 the Supreme Court of Montana upheld the District Court's decision that the City of Missoula can proceed with the condemnation of Mountain Water Company's assets. Upon taking possession of Mountain Water's assets, the compensation to be paid by the City of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. $88.6 million). In addition, legal fees, interest, and property tax reimbursements are expected to result in APUC receiving proceeds of at least U.S. $103.5 million, in accordance with agreements entered in to at the time of the Park Water acquisition.

As part of the condemnation process, Mountain Water and the City of Missoula expect to resolve claims advanced by various real estate developers pertaining to Funded By Others ("FBO") contracts between each developer and Mountain Water. Under those FBO contracts, the developers paid for facilities to provide water service and are entitled to refund of such amounts over a 40 year period. These FBO contracts are recorded on the balance sheet of Mountain Water and reflect a non-discounted liability of U.S. $22.0 million at the acquisition date.

On January 29, 2016, the Montana PSC initiated a proceeding to consider the acquisition of the shares of Park Water by Liberty Utilities. In order to settle concerns raised by PSC staff, a negotiated stipulation agreement was achieved and approved by the PSC on July 7, 2016, whereby Mountain Water Company accepted a U.S. $1.1 million reduction in rates, subject to review at the time of the next rate case.

The Empire District Electric Company Acquisition

On February 9, 2016, the Distribution Group announced an agreement and plan of merger pursuant to which Liberty Utilities will indirectly acquire Empire and its subsidiaries. Empire is a Joplin, Missouri based regulated electric, gas (through its wholly-owned subsidiary The Empire District Gas Company), and water utility, collectively serving approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

The Transaction is expected to close in early 2017.

Closing is subject to receipt of certain state and federal regulatory and government approvals, including approval of the relevant commissions of the states of Arkansas, Kansas, Missouri and Oklahoma (collectively, the State Commissions), the Federal Communications Commission (the "FCC"), the Committee on Foreign Investment in the United States and the Federal Energy Regulatory Commission (the "FERC"), and the expiration or termination of the waiting period under the Hart-Scott-Rodino Act.

Applications to four state commissions (AR, KS, MO, OK) as well as FERC were filed on March 16, 2016.

On May 6, 2016, the FERC issued an order approving the proposed acquisition of Empire. The order did not contain any material conditions.

On May 12, 2016, the Oklahoma Corporation Commission issued an order approving the proposed acquisition of Empire by Liberty Utilities Co. The order approves the acquisition as filed, without any material conditions.

On September 7, 2016, the Missouri Public Service Commission issued an Order approving the transaction and the various stipulations achieved with numerous parties, including the Office of Public Counsel ("OPC") and the Missouri PSC Staff. The Stipulation conditions demonstrate that the transaction is consistent with the approval standard in Missouri.

On September 28, 2016, the Arkansas Public Service Commission ("APSC") approved a joint Stipulation and Settlement Agreement signed among Liberty Utilities, the Staff of the APSC and the Attorney General recommending approval of the merger subject to certain conditions which are not considered material.

On October 7, 2016, a stipulation agreement amongst APUC, Empire, and the Kansas Corporation Commission (KCC) staff was filed that resolves the KCC's review of the proposed acquisition of Empire. The agreement supports the transaction and calls for withdrawing Empire's pending Kansas rate case, a rate freeze that would extend to January 1, 2019, and Empire to be permitted to file for a rate increase in the near future under its environmental recovery rider for certain costs associated with converting the gas fired Riverton 12 plant to a combined-cycle, from a simple-cycle, unit. The statutory time limit for a final KCC decision is January 10, 2017, however a decision is expected in late 2016, allowing the transaction to close in early 2017.

Treasury Risk Management Pertaining to Closing of the Acquisition

The $1.15 billion of convertible debentures raised in the first quarter of 2016 to fund the acquisition of Empire are denominated in Canadian dollars. In order to mitigate the effects of a potential funding mismatch due to fluctuations in the foreign exchange rate, the Company has converted approximately 73% of the total expected proceeds into U.S. dollars by purchasing spot and forward currency exchange contracts with an average U.S. exchange rate of approximately 1.32. Hedge accounting is not applicable, hence any changes in value are recorded in the Statement of Operations. The Company has carried out these transactions over the course of the current year.

In contemplation of the Empire acquisition, the Distribution Group expects to access the U.S. debt capital markets early in the first quarter of 2017. In anticipation of this debt financing, on October 25, 2016, the Distribution Group entered into hedges to fix the underlying interest rates for U.S. $500.0 million. The hedges mature on February 13, 2017 and consist of forward purchase contracts of U.S. $250.0 million 10 year U.S. treasuries at an approximate interest rate of 1.84% and U.S. $250.0 million 30 year U.S. treasuries at an approximate interest rate of 2.55%. Hedge accounting treatment has been applied to these transactions. Consequently, changes in fair value, to the extent deemed effective, are recorded in Other Comprehensive Income.

TRANSMISSION BUSINESS GROUP

California Intrastate Transmission

The Transmission Group is in the process of upgrading the North Lake Tahoe Transmission System to enable eventual operation of the entire system at 120 kilovolts (KVs). The project is expected to improve the reliability of the system and ensure sufficient capacity to serve the existing customer base. The project will be separated into three phases:

Phase I: Involved rebuilding the 650 Line (10 miles) to 120kV which runs from Northstar to Kings Beach, California. Subsequent to the quarter, the line was energized thereby completing Phase I for total costs of approximately U.S. $21.5 million;

Phase II: Will result in an upgrade the 650 Line substations, which will begin upon receipt of the CPUC's approval of a third party study confirming demand is approaching 89 MWs; this study is currently underway in addition to a Tier 2 Advice Letter for Phase II being submitted to the CPUC. Construction of Phase II will begin in 2017 with completion estimated to occur later in fiscal 2017 at an estimated total cost of approximately U.S. $27.7 million;

Phase III: Will result in a rebuild of the 625 Line from 60 kV to 120 kV (15 miles) at an estimated total cost of approximately U.S. $24.3 million. This phase will begin once the system demand approaches 100 MWs.

APUC: CORPORATE AND OTHER EXPENSES

	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	**2016**	**2015**	**2016**	**2015**
Corporate and other expenses:				
Administrative expenses	**$ 12.1**	$ 8.5	**$ 33.9**	$ 27.5
(Gain)/Loss on foreign exchange	**(3.4)**	(1.6)	**(1.8)**	(2.9)
Interest expense on convertible debentures and bridge financing related to the acquisition of Empire	**17.0**	—	**39.4**	—
Interest expense	**17.8**	15.4	**53.5**	48.6
Interest, dividend, equity, and other income[1]	**(0.7)**	(0.9)	**(2.4)**	(2.0)
Other (gains)/losses	**(2.2)**	0.9	**(11.0)**	(1.3)
Acquisition-related costs	**2.1**	0.6	**9.6**	1.4
(Gain)/loss on derivative financial instruments	**(4.4)**	0.2	**(2.9)**	(2.2)
Income tax expense	**1.8**	3.1	**25.6**	32.0

[1] Excludes income directly pertaining to the Generation and Distribution Groups (disclosed in the relevant sections).

2016 Third Quarter Corporate and Other Expenses

During the three months ended September 30, 2016, administrative expenses totalled $12.1 million as compared to $8.5 million in the same period in 2015. The $3.6 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the three months ended September 30, 2016, interest expense on convertible debentures and bridge financing totalled $17.0 million, as compared to nil in the same period in 2015. Convertible debentures, which are expected to convert to common shares upon closing of the Empire acquisition, were issued to finance the equity required for the transaction. Please see note 10 of the financial statements for further disclosure.

For the three months ended September 30, 2016, interest expense totalled $17.8 million as compared to $15.4 million in the same period in 2015. The interest expense for the period is a result of a U.S. $235.0 million term facility issued early 2016, and the assumed debt on the acquisition of the Park Water System.

For the three months ended September 30, 2016, gain on long lived assets and other gains totalled a gain of $2.2 million as compared to a loss of $0.9 million in the same period in 2015. The increase is primarily due to gains on marketable securities and insurance recoveries.

For the three months ended September 30, 2016, gain on derivative financial instruments totalled $4.4 million as compared to a loss of $0.2 million in the same period in 2015. The increase was primarily driven by mark-to-market gains on foreign currency hedges.

For the three months ended September 30, 2016, an income tax expense of $1.8 million was recorded as compared to an income tax expense of $3.1 million during the same period in 2015. The decrease is primarily due to additional interest expense on the convertible debentures.

2016 Year-to-Date Corporate and Other Expenses

During the nine months ended September 30, 2016, administrative expenses totalled $33.9 million, as compared to $27.5 million in the same period in 2015. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth and a stronger U.S. dollar.

For the nine months ended September 30, 2016, interest expense on convertible debentures and bridge financing totalled $39.4 million, as compared to nil in the same period in 2015. Convertible debentures, which are expected to convert to common shares upon closing of the Empire acquisition, were issued to finance the equity required for the transaction. Please see note 10 of the financial statements for further disclosure.

For the nine months ended September 30, 2016, interest expense totalled $53.5 million, as compared to $48.6 million in the same period in 2015. The interest expense for the period is a result of new indebtedness including: U.S. $160.0 million private placement issued in the second quarter of 2015, U.S. $235.0 million term facility issued the first quarter of 2016, and the assumed debt on the acquisition of the Park Water System. These items were offset by repayments of the Shady Oaks Wind Facility senior debt, reduced draws on the company's credit facilities and higher capitalized interest.

For the nine months ended September 30, 2016, gain on long lived assets and other gains totalled a gain of $11.0 million as compared to a gain of $1.3 million in the same period in 2015. The increase is primarily due to: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see note 14 in the financial statements) partially offset by (iii) the write-down of the company's equity interest in the natural gas development projects which have been canceled by the developer.

For the nine months ended September 30, 2016, acquisition related costs totalled $9.6 million as compared to $1.4 million in the same period in 2015. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the nine months ended September 30, 2016, the gain on derivative financial instruments totalled $2.9 million, as compared to a gain of $2.2 million in the same period in 2015. The increase was due to mark-to market gains on foreign currency hedges offset by losses on the ineffective portion of derivative financial instruments accounted for as hedges.

An income tax expense of $25.6 million was recorded in the nine months ended September 30, 2016, as compared to an income tax expense of $32.0 million during the same period in 2015. The decrease in income tax expense for the nine months ended September 30, 2016 is primarily due to a one-time non-cash charge of $2.7 million to deferred income taxes recorded during the nine months ended September 30, 2015 as a result of an agreement reached with the Canada Revenue Agency (“CRA”) related to the Unit Exchange Transaction and decreased earnings as a result of additional interest expense on the convertible debentures.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

The following table is derived from and should be read in conjunction with the unaudited interim consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	2016	2015	2016	2015
Net earnings attributable to shareholders	**$ 17.7**	$ 16.5	**$ 84.6**	$ 79.5
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**2.2**	0.2	**4.3**	1.3
Equity (income) loss from non-consolidated entities	**2.0**	—	**1.6**	—
Operating profit from non-consolidated entities	**1.0**	—	**2.4**	—
Loss from discontinued operations, net of tax	**—**	0.2	**—**	1.0
Income tax expense	**1.8**	3.1	**25.6**	32.0
Interest expense on convertible debentures and bridge financing	**17.0**	—	**39.4**	—
Interest expense	**17.8**	15.4	**53.5**	48.6
Other gains	**(2.3)**	(0.6)	**(8.6)**	(3.0)
(Gain)/loss on long-lived assets	**0.2**	1.5	**(2.5)**	1.8
Acquisition related costs	**2.1**	0.6	**9.6**	1.4
(Gain) / loss on derivative financial instruments	**(4.4)**	0.2	**(2.9)**	(2.2)
Realized gain / (loss) on energy derivative contracts	**—**	—	**(0.9)**	0.6
(Gain) / loss on foreign exchange	**(3.4)**	(1.6)	**(1.8)**	(2.9)
Depreciation and amortization	**39.7**	34.7	**134.3**	107.9
Adjusted EBITDA	**$ 91.4**	$ 70.2	**$ 338.6**	$ 266.0

HLBV represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and nine months ended September 30, 2016 amounted to $5.2 million and $27.4 million respectively.

Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the unaudited interim consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Net Earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to Adjusted Net Earnings exclusive of these items:

(all dollar amounts in $ millions)	Three Months Ended September 30 2016	Three Months Ended September 30 2015	Nine Months Ended September 30 2016	Nine Months Ended September 30 2015
Net earnings attributable to shareholders	**$ 17.7**	$ 16.5	**$ 84.6**	$ 79.5
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**—**	0.2	**—**	1.0
(Gain) / Loss on derivative financial instruments, net of tax	**(2.6)**	0.1	**(1.7)**	(1.3)
Realized gain / (loss) on derivative financial instruments, net of tax	**—**	(0.4)	**(0.6)**	(0.7)
Loss (gain) on long-lived assets, net of tax	**0.2**	1.5	**(1.8)**	1.8
(Gain) / Loss on foreign exchange, net of tax	**(2.5)**	(1.0)	**(1.3)**	(1.8)
Interest expense on convertible debentures and bridge financing fees, net of tax	**12.5**	—	**28.9**	—
Acquisition costs, net of tax	**1.3**	0.4	**5.9**	0.8
Deferred tax expense due to an agreement with the CRA related to the Unit Exchange Transaction	**—**	—	**—**	2.7
Adjusted Net Earnings	**$ 26.6**	$ 17.3	**$ 114.0**	$ 82.0
Adjusted Net Earnings per share[1]	**$ 0.09**	$ 0.06	**$ 0.40**	$ 0.31

[1] Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

For the three months ended September 30, 2016, Adjusted Net Earnings totalled $26.6 million as compared to Adjusted Net Earnings of $17.3 million, an increase of $9.3 million as compared to the same period in 2015. The increase in Adjusted Net Earnings for the three months ended September 30, 2016 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2015.

For the nine months ended September 30, 2016, Adjusted Net Earnings totalled $114.0 million as compared to Adjusted Net Earnings of $82.0 million, an increase of $32.0 million as compared to the same period in 2015. The increase in Adjusted Net Earnings for the quarter is primarily due to higher income from operations partially offset by higher depreciation and amortization expense.

Reconciliation of Adjusted Funds from Operations to Cash Flows from Operating Activities

The following table is derived from and should be read in conjunction with the unaudited interim consolidated statement of operations and unaudited interim consolidated statement of cash flows. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Funds from Operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to Adjusted Funds from Operations exclusive of these items:

	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	2016	2015	2016	2015
Cash flows from operating activities	**$ 22.6**	$ 76.2	**$ 166.0**	$ 167.5
Add (deduct):				
Changes in non-cash operating items	**18.7**	(22.9)	**43.0**	28.9
Cash used in discontinued operations	**—**	0.4	**—**	1.7
Production based cash contributions from non-controlling interests	**—**	—	**9.5**	10.8
Interest expense on convertible debentures and bridge financing fees	**17.0**	—	**39.4**	—
Acquisition costs	**2.1**	0.6	**9.6**	1.4
Cash generated from sale of long-lived assets	**—**	—	**(8.6)**	—
Cash generated from non-consolidated entities	**0.6**	—	**1.1**	—
Adjusted Funds from Operations	**$ 61.0**	$ 54.3	**$ 260.0**	$ 210.3
Adjusted Funds from Operations per share[1]	**$ 0.22**	$ 0.22	**$ 0.95**	$ 0.85

1 Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

For the three months ended September 30, 2016, Adjusted Funds from Operations totalled $61.0 million as compared to Adjusted Funds from Operations of $54.3 million, an increase of $6.7 million as compared to the same period in 2015.

For the nine months ended September 30, 2016, Adjusted Funds from Operations totalled $260.0 million as compared to Adjusted Funds from Operations of $210.3 million, an increase of $49.7 million as compared to the same period in 2015.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

	Three Months Ended September 30		Nine Months Ended September 30	
(all dollar amounts in $ millions)	2016	2015	2016	2015
Generation Group	**$ 25.1**	$ 22.3	**$ 86.3**	$ 51.2
Generation Group - Acquisition of Operating Entities	**345.1**	15.5	**345.1**	83.1
Total Generation Group	**$ 370.2**	$ 37.8	**$ 431.4**	$ 134.3
Distribution Group	**$ 61.9**	$ 52.6	**$ 133.3**	$ 101.0
Transmission Group	**7.2**	4.8	**12.1**	6.7
Corporate	**(2.0)**	0.4	**2.3**	3.0
Total	**$ 437.3**	$ 95.6	**$ 579.1**	$ 245.0

2016 Third Quarter Property Plant and Equipment Expenditures

During the three months ended September 30, 2016, the Generation Group incurred capital expenditures of $25.1 million as compared to $22.3 million during the same period in 2015. The capital expenditures primarily relate to construction at the Donnacona Hydro Facility and the Bakersfield II Solar Project, as well as development spending at the Great Bay Solar and Amherst Island Wind Projects. The prior year investment was related to completion of the Morse Wind and Bakersfield I Solar Facilities, in addition to continued development of the Great Bay Solar and Amherst Island Wind Projects. During the three months ended September 30, 2016 the Generation Group incurred $345.1 million as a result of the acquisition of the Odell Wind Project. Of the total cost, $236.1 million was received from Tax Equity Investors.

During the three months ended September 30, 2016, the Distribution Group invested $61.9 million (U.S. $47.5 million) in capital expenditures as compared to $52.6 million (U.S. $40.1 million) during the same period in 2015. The Distribution Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to safety and reliability at the gas systems.

During the three months ended September 30, 2016, the Transmission Group invested $7.2 million (U.S. $5.5 million) in capital expenditures as compared to $4.8 million (U.S. $3.7 million) during the same period in 2015. The Transmission Group's investment was related to Phase I of the North Lake Tahoe Transmission System upgrade. Phase I involves the rebuilding of the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2016 Year-to-Date Property Plant and Equipment Expenditures

During the nine months ended September 30, 2016, the Generation Group incurred capital expenditures of $86.3 million, as compared to $51.2 million during the same period in 2015. The capital expenditures primarily relate to continued construction at the Bakersfield II Solar Project as well as development spending at the Great Bay Solar Project and the Amherst Wind Project. The prior year investment was related to completion of the Morse Wind and Bakersfield I Solar Facilities, in addition to continued development of the Great Bay Solar and Amherst Island Wind Projects. During the nine months ended September 30, 2016, the Generation Group incurred $345.1 million as a result of the acquisition of the Odell Wind Project. Of the total cost, $236.1 million was received from Tax Equity Investors.

During the nine months ended September 30, 2016, the Distribution Group invested $133.3 million (U.S. $100.8 million) in capital expenditures as compared to $101.0 million (U.S. $80.2 million) during the same period in 2015. The Distribution Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, pipe replacements, leak repairs, and pipeline corrosion protection systems relating to safety and reliability at the gas systems.

During nine months ended September 30, 2016, the Transmission Group invested $12.1 million (U.S. $9.1 million) in capital expenditures as compared to $6.7 million (U.S. $5.3 million) during the same period in 2015. The Transmission Group's investment was related to Phase I of the North Lake Tahoe Transmission System upgrade.

2016 Capital Investments

In 2016, the company plans to spend between $700.0 million and $925.0 million on capital investment opportunities. Actual expenditures during the course of 2016 may vary due to timing on various project investments and the realized U.S. dollar exchange rate.

Expected 2016 capital investment ranges are as follows:

(all dollar amounts in $ millions)			
Generation Group development projects, including joint ventures	$ 450.0	-	$ 600.0
Generation Group maintenance capital expenditure program	30.0	-	45.0
Distribution Group rate base investments	195.0	-	250.0
Transmission Group development projects	25.0	-	30.0
Total	**$ 700.0**	**-**	**$ 925.0**

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, funds committed by tax equity investors, revolving credit facilities, as well as the debt and equity capital markets to finance its 2016 capital investments.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Generation Group, and the Distribution Group to manage the liquidity and working capital requirements of each division (collectively the "Facilities").

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at September 30, 2016:

(all dollar amounts in $ millions)	As at September 30, 2016 Corporate	Generation	Distribution	Total	As at Dec 31, 2015 Total
Committed facilities	$ 65.0	$ 439.4	$ 262.3	**$ 766.7**	$ 783.3
Funds drawn on facilities	—	(171.0)	(13.1)	**(184.1)**	(27.3)
Letters of credit issued	(11.9)	(95.1)	(40.9)	**(147.9)**	(164.4)
Liquidity available under the facilities	**53.1**	**173.3**	**208.3**	**434.7**	591.6
Cash on hand				**47.5**	124.4
Total liquidity and capital reserves	**$ 53.1**	**$ 173.3**	**$ 208.3**	**$ 482.2**	$ 716.0

As at September 30, 2016, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $11.9 million of outstanding letters of credit. The facility matures on November 19, 2017 and is subject to customary covenants.

As at September 30, 2016, the Generation Group's facilities consisted of a $350.0 million Generation Credit Facility and $89.4 million Generation Letter of Credit Facility (Cdn. $50.0 million and U.S. $30.0 million). As at September 30, 2016, the group had drawn $171.0 million and had $95.1 million in outstanding letters of credit. The facilities mature on July 31, 2019 and October 30, 2016, respectively. Subsequent to quarter end, the Company extended the maturity of the Generation Letter of Credit Facility to October 31, 2017.

As at September 30, 2016, the Distribution Group's $262.3 million (U.S.$200.0 million) senior unsecured revolving credit facility had drawn $13.1 million (U.S. $10.0 million) and had $40.9 million (U.S. $31.2 million) of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants.

Subsequent to the quarter, on November 9, 2016, the Company extended the maturity date of the U.S. $235.0 million term credit facility from July 5, 2017 to July 5, 2018. The extension did not result in any material changes to the loan or related covenants.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2016 is shown below:

(all dollar amounts in $ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Principal repayments on debt obligations[1]	**$ 2,012.5**	$ 75.6	$ 677.9	$ 296.6	$ 962.4
Convertible debentures	**358.5**		—	—	358.5
Advances in aid of construction	**109.1**	2.9	—	—	106.2
Interest on long-term debt obligations	**826.7**	148.1	145.8	113.0	419.8
Purchase obligations	**195.3**	195.3	—	—	—
Environmental obligations	**73.1**	3.1	15.1	13.5	41.4
Derivative financial instruments:					
Cross currency swap	**89.6**	3.7	6.9	46.6	32.4
Interest rate swap	**22.8**	—	22.8	—	—
Energy derivative contracts	**0.4**	0.3	0.1	—	—
Purchased power	**169.3**	51.6	70.2	47.5	—
Gas delivery, service and supply agreements	**265.7**	62.5	83.9	52.9	66.4
Long term service agreements	**717.5**	39.9	81.6	89.8	506.2
Capital projects	**261.0**	213.2	47.4	0.4	—
Operating leases	**165.2**	7.5	14.1	13.5	130.1
Other obligations	**77.4**	12.0	—	—	65.4
Total obligations	**$ 5,344.1**	**$ 815.7**	**$ 1,165.8**	**$ 673.8**	**$ 2,688.8**

[1] Exclusive of deferred financing costs and bond premium/discount at the time of issuance or acquisition.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at September 30, 2016, APUC had 273,314,425 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

During the first quarter, the Company sold $1.15 billion principal amount of 5.0% convertible unsecured subordinated debentures (the "Debentures"). At the option of the holders, each Debenture will be convertible into common shares of the Company at any time after the Company acquires Empire, at a conversion price of $10.60 per common share.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at September 30, 2016, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares of APUC. As at September 30, 2016, 57.3 million common shares representing approximately 21% of total shares outstanding had been registered with the Reinvestment Plan. During the quarter ended September 30, 2016, 599,375 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on October 14, 2016, an additional 725,171 common shares were issued under the Reinvestment Plan.

SHARE BASED COMPENSATION PLANS

For the nine months ended September 30, 2016, APUC recorded $4.1 million in total share-based compensation expense, as compared to $3.7 million for the same period in 2015. There is no tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at September 30, 2016, total unrecognized compensation costs related to non-vested options and share unit awards were $4.0 million and $2.7 million, respectively, and are expected to be recognized over a period of 1.93 and 1.86 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the nine months ended September 30, 2016, the Company granted 2,596,025 options to executives of the Company. The options allow for the purchase of common shares at a price of $10.86, the market price of the underlying common share at the date of grant. In March 2016, executives of the Company exercised 3,715,663 stock options at a weighted average exercise price of $5.25 in exchange for 2,720,980 common shares issued from treasury and 994,683 shares withheld as payment in lieu of minimum tax withholdings.

As at September 30, 2016, a total of 6,045,014 options are issued and outstanding under the plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. During the nine months ended September 30, 2016, the Company granted (including dividends) 212,301 PSUs to executives and employees of the Company. During the second quarter the Company settled 173,441 PSU by issuing 87,361 shares from treasury, with the balance withheld as payment in lieu of minimum tax withholdings.

As at September 30, 2016, a total of 586,347 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% of their annual compensation in deferred share units (“DSUs”) and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the nine months ended September 30, 2016, the Company issued 49,605 DSUs to the directors of the Company.

As at September 30, 2016, a total of 207,076 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the “ESPP”) which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the nine months ended September 30, 2016, the Company issued 100,761 common shares to employees under the ESPP.

As at September 30, 2016, a total of 452,527 shares had been issued under the ESPP.

RELATED PARTY TRANSACTIONS

Emera Inc.

A member of the Board of APUC is an executive at Emera. For the three and nine months ended September 30, 2016, the Company's energy services business sold electricity to Maine Public Service Company (“MPS”), and Bangor Hydro (“BH”) subsidiaries of Emera, amounting to U.S. $3.1 million and U.S. $8.0 million, respectively as compared to U.S. $1.7 million and U.S. $4.8 million, respectively, during the same period in the prior year. For the three and nine months ended September 30, 2016, Liberty Utilities purchased natural gas amounting to U.S. $0.5 million and U.S. $2.8 million, respectively, as compared to U.S. $0.1 million and U.S. $1.4 million, respectively, from Emera for its gas utility customers in the same period in the prior year. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction. On May 13, 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The total cost of the contract is estimated at $8.6 million and is expected to be completed in 2016. The contract followed a market based request for proposal process.

There was U.S. $0.1 million included in accruals for the nine months ended September 30, 2016 related to these transactions.

Equity-method investments

The Company provides administrative and operating services to its equity-method investees, earns royalty revenue and is reimbursed for incurred costs. To that effect, during the three and nine months ended September 30, 2016, the Company charged its equity-method investees $0.9 million and $2.5 million, respectively, as compared to $0.5 million and $1.5 million, respectively, during the same period in 2015.

Senior Executives

Ian Robertson and Chris Jarratt are senior executives of APUC (collectively "Senior Executives").

The Company owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate (“Trafalgar”). In 1997, Trafalgar went into default under its debt obligations and an entity partially and indirectly owned by Senior Executives (the "Related Entity"), moved to foreclose on the assets on behalf of the Company. Subsequent to the foreclosure action, Trafalgar went into bankruptcy. APUC and the Related Entity have jointly pursued litigation and bankruptcy proceedings with Trafalgar since 2002.

In 2003 and 2004, the Company reimbursed the Related Entity $1.0 million of the approximately $2.0 million in third-party legal fees it had initially funded and APUC agreed to fund future legal fees and other liabilities. It was agreed that any net proceeds from the litigation and bankruptcy proceedings would be shared proportionally to the quantum of net legal costs funded by each party. On June 30, 2016, the Company received U.S. $10.1 million in proceeds from the settlement of this matter and, subsequent to quarter-end, paid U.S. $2.9 million to the Related Entity as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in the second quarter.

ENTERPRISE RISK MANAGEMENT

An enterprise risk management ("ERM") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC’s ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. Reference should be made to APUC's most recent annual MD&A and its most recent AIF.

Treasury Risk Management

Market Price Risk

The Distribution Business Group is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

The Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the group along with residual exposures to the market are detailed below:

On May 15, 2012, the Generation Group entered into a financial hedge, which expires December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge is structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. The annual unhedged production based on long term projected averages is approximately 16,000 MW-hrs annually. Therefore, each U.S. $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. $0.2 million on an annualized basis.

The July 1, 2012 acquisition of Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $0.4 million for the year.

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2 million for the year.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at September 30, 2016, the Generation Group had not entered into any such short-term derivative contracts.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $0.5 million for the year.

Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had no amounts outstanding as at September 30, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Generation Credit Facility is subject to a variable interest rate and had $171.0 million outstanding as at September 30, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $1.7 million annually;
- The Distribution Credit Facility is subject to a variable interest rate and had $13.1 million (U.S. $10.0 million) outstanding as at September 30, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually;
- The Corporate Term Facility is subject to a variable interest rate and had $308.2 million (U.S. $235.0 million) outstanding as at September 30, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $3.1 million annually;
- The Park Water System term credit facility is subject to a variable interest rate and had $29.1 million (U.S. $22.5 million) outstanding as at September 30, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually; and
- To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings.
    - In the fourth quarter of 2014, the Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.
    - Subsequent to the quarter, the Distribution Group entered into a hedge to fix the underlying interest rate for U.S. $500.0 million of anticipated debt financing associated with the Empire acquisition. The hedges mature on February 13, 2017 and consist of forward purchase contracts of U.S.$ 250.0 million 10 year US treasuries and U.S. $250.0 million 30 year U.S. treasuries. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

Tax Risk and Uncertainty

Although APUC is of the view that all expenses being claimed by APUC are reasonable and that the cost amount of APUC's depreciable properties have been correctly determined, there can be no assurance that the Canada Revenue Agency ("CRA") or the Internal Revenue Service will agree with this determination. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to shareholders.

Liquidity Risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due.

Both the Generation Group and the Distribution Group have established financing platforms to access new liquidity from the capital markets as requirements arise. APUC continually monitors the maturity profile of its debt and adjusts accordingly to ensure sufficient liquidity exists to meet liabilities when due.

As at September 30, 2016, APUC and its subsidiaries had a combined $434.7 million of liquidity available under the Facilities remaining and $47.5 million of cash on hand resulting in $482.2 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.4235 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success.

The current and long term portion of debt and convertible debentures, exclusive of deferred financing costs and bond premium/discount at the time of issuance or acquisition totals $2,371.1 million. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

The cash flow generated from several of APUC's operating facilities is subordinated to senior operating facility debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

OPERATIONAL RISK MANAGEMENT

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against various Algonquin entities in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Algonquin entities and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). Over the past 16 years there have been various District Court adversary proceedings and bankruptcy proceedings in connection with this matter.

By the end of July, 2015, the Trafalgar Hydro Facilities were all sold with the Bankruptcy Court's approval.

In June, 2016, all of the above legal proceedings were settled pursuant to the terms outlined in the United States Bankruptcy Court for the Northern District of New York Order Approving Terms of Settlement which was entered into Bankruptcy Court on June 20, 2016. Pursuant to the Global Settlement, U.S. Bank was allowed U.S. $1.5 million. The Algonquin entities were allowed approximately U.S. $10.1 million which amount was received on June 30, 2016.

Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011, onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court's judgment of March 12, 2015. The appeal was heard on December 14 and December 15, 2015. The Ontario Court of Appeal dismissed the OEFC's appeal by judgment dated April 19, 2016. OEFC has sought leave to appeal to the Supreme Court of Canada (the "SCC"). In addition, OEFC brought a motion to stay the payment of the retroactive payments pending its appeal to the SCC. On August 5, 2016, the Court of Appeal denied OEFC's motion for a stay. On September 13, 2015, the Ontario Court of Appeal dismissed the motion brought by the OEFC to set aside or vary the order. On October 21, 2016, the OEFC made retroactive payments of $5.1 million and $0.3 million of interest to Long Sault. Retention by Long Sault of the retroactive payment and any prior payments received in relation to the legal case continue to depend on the outcome of OEFC's application leave to appeal to the SCC and the outcome of the leave, if granted.

Côte Ste-Catherine Water Lease Dues

In October 2011, the Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4 million (including interest) to the Government of Quebec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6.9 million. In 2012, the Company paid an amount of $1.9 million to the Government of Quebec in relation to the early years covered by the claim in order to mitigate the impact of accruing interest on any amount ultimately determined to be payable or recoverable. The parties continue to engage in settlement discussions with a view to resolving this matter.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended September 30, 2016:

(all dollar amounts in $ millions except per share information)	4th Quarter 2015	1st Quarter 2016	2nd Quarter 2016	3rd Quarter 2016
Revenue	$ 260.3	$ 341.7	$ 222.8	$ 221.3
Adjusted EBITDA	109.6	147.9	99.2	91.4
Net earnings / (loss) attributable to shareholders from continuing operations	38.1	42.0	24.8	17.7
Net earnings / (loss) attributable to shareholders	38.0	42.0	24.8	17.7
Net earnings / (loss) per share from continuing operations	0.14	0.15	0.08	0.06
Net earnings / (loss) per share	0.14	0.15	0.08	0.06
Adjusted Net Earnings	39.7	56.1	30.9	26.6
Adjusted Net Earnings per share	0.15	0.21	0.11	0.09
Total assets	4,991.7	5,615.5	5,555.0	6,020.8
Long term debt[1]	1,486.8	2,214.5	2,199.9	2,380.8
Dividend declared per common share	$ 0.13	$ 0.13	$ 0.14	$ 0.14

	4th Quarter 2014	1st Quarter 2015	2nd Quarter 2015	3rd Quarter 2015
Revenue	$ 259.3	$ 381.9	$ 196.2	$ 189.6
Adjusted EBITDA	84.3	114.5	81.1	70.2
Net earnings / (loss) attributable to shareholders from continuing operations	33.1	43.1	20.6	16.7
Net earnings/(loss) attributable to shareholders	31.6	43.1	19.9	16.5
Net earnings / (loss) per share from continuing operations	0.13	0.16	0.07	0.06
Net earnings/(loss) per share	0.13	0.16	0.07	0.05
Adjusted Net Earnings	35.2	42.6	22.2	17.3
Adjusted Net Earnings per share	0.14	0.17	0.08	0.06
Total assets	4,105.1	4,531.4	4,396.5	4,759.0
Long term debt[1]	1,271.7	1,482.7	1,440.3	1,613.3
Dividend declared per common share	$ 0.10	$ 0.11	$ 0.12	$ 0.13

[1] Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $189.6 million and $381.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $43.1 million and a net earnings of $16.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

DISCLOSURE CONTROLS

As of September 30, 2016, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15 (e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of September 30, 2016, APUC's disclosure controls and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and the CFO, is responsible for establishing and maintaining internal control over financial reporting. Management, as at the end of the period covered by this interim filing, designed internal controls over financial reporting to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. The control framework management used to design the issuer's internal control over financial reporting is that established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

For the nine months ended September 30, 2016, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its unaudited interim financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

Except for adopted accounting policies described in note 2(a), the significant accounting policies and estimates applied to the unaudited interim consolidated financial statements of APUC for the nine months ended September 30, 2016, are consistent with those disclosed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2015, available on SEDAR.

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 47,520	$ 124,353
Accounts receivable, net (note 4)	154,794	186,681
Natural gas in storage	23,418	28,502
Regulatory assets (note 5)	47,298	32,213
Prepaid expenses	22,168	18,409
Derivative instruments (note 21)	17,058	15,039
Other current assets	19,328	18,537
	331,584	423,734
Property, plant and equipment, net	4,584,509	3,877,170
Intangible assets, net	65,311	74,477
Goodwill	301,412	110,493
Regulatory assets (note 5)	239,115	213,102
Derivative instruments (note 21)	75,597	73,322
Long-term investments (note 6)	364,975	174,802
Deferred income taxes	29,573	18,109
Other assets	28,752	26,516
	$ 6,020,828	$ 4,991,725

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	September 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 25,752	$ 50,428
Accrued liabilities	169,551	193,320
Dividends payable	37,966	41,802
Regulatory liabilities (note 5)	51,136	44,167
Long-term debt (note 7)	75,628	8,945
Other long-term liabilities and deferred credits (note 9)	27,887	36,621
Other liabilities	7,808	16,593
	395,728	391,876
Long-term debt (note 7)	1,946,669	1,477,850
Convertible debentures (note 10)	358,506	—
Regulatory liabilities (note 5)	131,451	131,180
Deferred income taxes	248,736	175,799
Derivative instruments (note 21)	108,816	106,628
Pension and other post-employment benefits (note 8)	157,200	150,094
Other long-term liabilities (note 9)	254,451	223,135
Preferred shares, Series C	17,548	17,548
	3,223,377	2,282,234
Redeemable non-controlling interest	19,828	25,751
Equity:		
Preferred shares	213,805	213,805
Common shares (note 11(a))	1,963,669	1,808,894
Subscription receipts (note 11(b))	—	110,503
Additional paid-in capital	36,902	38,241
Deficit	(560,529)	(523,116)
Accumulated other comprehensive income (note 12)	168,593	286,737
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,822,440	1,935,064
Non-controlling interests (note 6(a))	559,455	356,800
Total Equity	2,381,895	2,291,864
Commitments and contingencies (note 19)		
Subsequent events (notes 3, 6, 7, 14, 16, 19 and 21)		
	$ 6,020,828	$ 4,991,725

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Revenue				
Regulated electricity distribution	$ 54,245	$ 53,370	$165,548	$169,526
Regulated gas distribution	49,372	49,304	282,307	349,528
Regulated water reclamation and distribution	50,978	21,891	139,385	58,142
Non-regulated energy sales	56,390	49,486	176,149	159,575
Other revenue	10,292	15,530	22,395	30,822
	221,277	189,581	785,784	767,593
Expenses				
Operating expenses	80,349	73,221	244,731	211,012
Regulated electricity purchased	28,352	29,250	92,284	100,710
Regulated gas purchased	9,291	10,017	88,880	168,338
Regulated water purchased	3,504	—	9,228	—
Non-regulated energy purchased	6,018	5,270	15,042	22,645
Administrative expenses	12,071	8,482	33,864	27,460
Depreciation and amortization	39,733	34,673	134,267	107,891
Gain on foreign exchange	(3,355)	(1,635)	(1,782)	(2,921)
	175,963	159,278	616,514	635,135
Operating income from continuing operations	45,314	30,303	169,270	132,458
Interest expense on convertible debentures and bridge financing (notes 7 and 10)	16,994	—	39,386	—
Interest expense on long-term debt and others	17,773	15,407	53,511	48,567
Interest, dividend, equity and other income	(1,505)	(2,344)	(6,435)	(6,329)
Other gains	(2,343)	(602)	(8,555)	(3,011)
Acquisition-related costs	2,148	605	9,638	1,363
Loss (gain) on long-lived assets, net (notes 6(e) and 14)	150	1,485	(2,459)	1,757
Loss (gain) on derivative financial instruments (note 21(b)(iv))	(4,419)	221	(2,902)	(2,236)
	28,798	14,772	82,184	40,111
Earnings from continuing operations before income taxes	16,516	15,531	87,086	92,347
Income tax expense (recovery) (note 16)				
Current	2,532	2,123	7,899	6,519
Deferred	(737)	955	17,732	25,433
	1,795	3,078	25,631	31,952
Earnings from continuing operations	14,721	12,453	61,455	60,395
Loss from discontinued operations, net of tax	—	(241)	—	(954)
Net earnings	14,721	12,212	61,455	59,441
Net loss attributable to non-controlling interests (notes 6(a) and 15)	(3,024)	(4,242)	(23,123)	(20,051)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 17,745	$ 16,454	$ 84,578	$ 79,492
Series A and D Preferred shares dividend (note 13)	2,600	2,600	7,800	7,800
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 15,145	$ 13,854	$ 76,778	$ 71,692
Basic net earnings per share (note 17)	$ 0.06	$ 0.05	$ 0.28	$ 0.29
Diluted net earnings per share (note 17)	0.05	0.05	0.28	0.28

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Three months ended September 30,		Nine months ended September 30,	
	2016	**2015**	**2016**	**2015**
Net earnings	$ 14,721	$ 12,212	$ 61,455	$ 59,441
Other comprehensive (loss) income:				
Foreign currency translation adjustment, net of tax recovery of $Nil (2015 - $Nil), respectively (note 21(b)(iii)	53,659	104,137	(128,367)	227,555
Change in fair value of cash flow hedges', net of tax expense of $4,746 and recovery of $1,341 (2015 - tax expense $6,790 and $13,199), respectively (note 21(b)(ii))	(19,789)	10,793	(6,148)	18,733
Change in fair value of available-for-sale investments	(7)	(164)	20	(165)
Change in pension and other post-employment benefits, net of tax expense of $137 and recovery of $2,257 (2015 - tax expense $134 and $3,221), respectively (note 8)	263	207	(3,532)	4,969
Other comprehensive income (loss), net of tax	34,126	114,973	(138,027)	251,092
Comprehensive income (loss)	48,847	127,185	(76,572)	310,533
Comprehensive income (loss) attributable to the non-controlling interests	1,174	18,707	(43,006)	27,106
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ 47,673	$ 108,478	$ (33,566)	$ 283,427

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statement of Equity

(thousands of Canadian dollars)

For the nine months ended September 30, 2016

	Algonquin Power & Utilities Corp. Shareholders' Equity							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2015	$1,808,894	$213,805	$ 110,503	$38,241	$ (523,116)	$ 286,737	$356,800	$2,291,864
Net earnings (loss)	—	—	—	—	84,578	—	(23,123)	61,455
Redeemable non-controlling interests not included in equity	—	—	—	—	—	—	4,127	4,127
Other comprehensive loss	—	—	—	—	—	(118,144)	(19,883)	(138,027)
Dividends declared and distributions to non-controlling interests	—	—	—	—	(91,810)	—	(5,077)	(96,887)
Dividends and issuance of shares under dividend reinvestment plan	25,927	—	—	—	(25,927)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	9,454	9,454
Common shares issued upon conversion of subscription receipts (note 11 (b))	110,503	—	(110,503)	—	—	—	—	—
Common shares issued pursuant to share-based compensation	1,942	—	—	(1,487)	(417)	—	—	38
Common shares issued upon exercise of share options, net of withholding taxes (note 11 (c))	16,403	—	—	(3,935)	(3,837)	—	—	8,631
Share-based compensation	—	—	—	4,083	—	—	—	4,083
Non-controlling interest incurred (note 6(a))	—	—	—	—	—	—	237,157	237,157
Balance, September 30, 2016	$1,963,669	$213,805	$ —	$36,902	$ (560,529)	$ 168,593	$559,455	$2,381,895

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Cash provided by (used in):				
Operating Activities				
Net earnings	$ 14,721	$ 12,453	$ 61,455	$ 60,395
Adjustments and items not affecting cash:				
Depreciation and amortization	41,605	36,246	142,875	109,632
Deferred taxes	(737)	955	17,732	25,433
Unrealized gain on derivative financial instruments	(6,754)	(345)	(5,732)	(3,150)
Share-based compensation expense	1,449	1,813	4,083	3,727
Cost of equity funds used for construction purposes	(857)	(557)	(1,945)	(1,654)
Pension and post-employment expense	(6,497)	(77)	(9,273)	465
Write-down of long-lived assets	(2)	1,066	6,936	1,591
Unrealized gain on disposal of VIE	—	588	—	808
Decrease/(increase) in deferred income	(1,607)	1,483	(7,182)	862
Changes in non-cash operating items (note 20)	(18,725)	22,931	(42,974)	(28,886)
Cash used in discontinued operations	—	(400)	—	(1,684)
	22,596	76,156	165,975	167,539
Financing Activities				
Cash dividends on common shares	(30,027)	(20,685)	(87,846)	(59,043)
Cash dividends on preferred shares	(2,600)	(2,600)	(7,800)	(7,800)
Cash contributions from non-controlling interests	—	—	—	22
Production-based cash contributions from non-controlling interest	—	—	9,454	10,815
Cash distributions to non-controlling interests	(777)	(933)	(3,204)	(2,048)
Issuance of common shares, net of costs	364	335	1,045	820
Issuance of convertible debentures, net of costs	(422)	—	357,880	—
Proceeds from exercise of share options	(1,000)	—	18,493	—
Shares surrendered to fund withholding taxes on exercised share options	—	—	(5,218)	—
Increase in long-term debt	174,116	117,897	527,357	315,265
Decrease in long-term debt	—	(8,549)	(48,049)	(101,660)
Increase in other long-term liabilities	23	3,123	4,252	7,071
Decrease in other long-term liabilities	(379)	(1,466)	(3,200)	(3,548)
	139,298	87,122	763,164	159,894
Investing Activities				
Increase in other assets	(1,768)	(13,697)	(10,942)	(7,724)
Distributions in excess of equity income	2,024	911	1,454	769
Receipt of principal on notes receivable	—	168	11,685	2,988
Additions to property, plant and equipment	(92,267)	(80,031)	(233,959)	(161,877)
Increase in long-term investments	(196,166)	(52,503)	(338,111)	(123,159)
Acquisitions of operating entities	(99,995)	—	(432,283)	(3,717)
Proceeds from sale of long-lived assets	—	5,516	—	5,516
	(388,172)	(139,636)	(1,002,156)	(287,204)
Effect of exchange rate differences on cash	4,720	2,126	(3,816)	2,548
Increase (decrease) in cash and cash equivalents	(221,558)	25,768	(76,833)	42,777
Cash and cash equivalents, beginning of the period	269,078	26,282	124,353	9,273
Cash and cash equivalents, end of the period	$ 47,520	$ 52,050	$ 47,520	$ 52,050

Supplemental disclosure of cash flow information:	**2016**	**2015**	**2016**	**2015**
Cash paid during the year for interest expense	$ 47,492	$ 25,128	$ 106,414	$ 59,896
Cash paid during the year for income taxes	$ 2,244	$ 1,437	$ 10,931	$ 5,321
Non-cash financing and investing activities:				
Property, plant and equipment acquisitions in accruals	$ 37,522	$ 24,279	$ 37,522	$ 24,279
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 7,406	$ 8,311	$ 26,994	$ 21,372
Issuance of common shares upon conversion of subscription receipts	$110,503	$ —	$ 110,503	$ —
Acquisition of equity investments in exchange for loan receivable	$ 22,153	$ —	$ 22,153	$ —

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC is a diversified generation, transmission and distribution utility company. The distribution business group operates in the United States under the name of Liberty Utilities Co. ("Distribution Group") and provides rate regulated water, electricity and natural gas utility services. The generation business group operates under the name Algonquin Power Co. ("Generation Group") and owns or has interests in a portfolio of non-regulated North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission business group operates under the name Liberty Utilities (Pipeline & Transmission) ("Transmission Group") and invests in rate regulated electric transmission and natural gas pipeline systems in the United States and Canada.

1. Significant accounting policies

Basis of preparation

The accompanying unaudited interim consolidated financial statements and accompanying notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and Article 10 of Regulation S-X provided by the Securities and Exchange Commission ("SEC"). In the opinion of management, the unaudited interim consolidated financial statements include all adjustments that are of a recurring nature and necessary for a fair presentation of the results of interim operations.

The significant accounting policies applied to these unaudited interim consolidated financial statements of APUC are consistent with those disclosed in the consolidated financial statements of APUC for the year ended December 31, 2015 except for adopted accounting policies described in note 2(a).

APUC's operating results are subject to seasonal fluctuations that could materially impact quarter-to-quarter operating results and, thus, one quarter's operating results are not necessarily indicative of a subsequent quarter's operating results. APUC's hydroelectric energy assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally slower, while during the spring and fall periods flows are heavier. For APUC's wind energy assets, wind resources is typically stronger in spring, fall and winter and weaker in summer. APUC's solar energy assets experience greater insolation in summer, weaker in winter. APUC's water and wastewater utility assets' revenues fluctuate depending on the demand for water. During drier, hotter periods of the year, which occurs generally in the summer, demand for water is typically higher than during cooler, wetter periods of the year. During the winter period, natural gas distribution utilities experience higher demand than during the summer period. Where decoupling mechanisms exist, total volumetric revenue is prescribed by the Regulator and fluctuates based on usage while total fixed revenue will not fluctuate through the year. Different electrical distribution utilities can experience higher or lower demand in the summer or winter depending on the specific regional weather, industry characteristics and existence of a decoupling mechanism.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2015-16 Business Combinations (Topic 805): Simplifying the Accounting for Measurement Period Adjustments. Under this ASU, adjustments to the provisional amounts recorded in a business combination continue to be calculated as if the accounting had been completed at the acquisition date. However, the ASU eliminates the requirement to retrospectively account for those adjustments and instead requires recognition in the period that the adjustments are identified. The adoption of this ASU effective January 1, 2016 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2015-05, Intangibles: Goodwill and Other Internal-Use Software (Subtopic 350-40), to provide guidance to customers about whether a cloud computing arrangement includes a software license. The prospective adoption of this ASU effective January 1, 2016 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which ends the deferral granted to investment companies from applying the VIE guidance and makes targeted amendments to the current consolidation guidance. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the VIE characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. The adoption of this ASU effective January 1, 2016 had no impact on the Company's unaudited interim consolidated financial statements.

2. Recently issued accounting pronouncements (continued)

(a) Recently adopted accounting pronouncements (continued)

The FASB issued ASU 2015-01, Income Statement: Extraordinary and Unusual Items (Subtopic 225-20), to simplify income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. The adoption of this ASU effective January 1, 2016 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity. ASU 2014-16 clarifies how current guidance should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. In addition, ASU 2014-16 clarifies that in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (that is, the relative strength of the debt-like or equity-like terms and features given the facts and circumstances) when considering how to weigh those terms and features. The adoption of this ASU effective January 1, 2016 had no impact on the Company's unaudited interim consolidated financial statements.

The FASB issued ASU 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This newly issued accounting standard is intended to resolve the diverse accounting treatment of those awards in practice. The adoption of this ASU effective January 1, 2016 had no impact on the Company's unaudited interim consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2015-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This ASU amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory. The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. Current GAAP prohibits the recognition of current and deferred income taxes on these transactions until the asset has been sold to an outside party. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2016-15 Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments in order to eliminate current diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718) to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments to clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this Update is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships to clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The application of this standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2016-02, Leases (Topic 842) to increase transparency and comparability among organizations utilizing leases. This ASU requires lessees to recognize the assets and liabilities arising from all leases on the balance sheet, but the effect of leases in the statement of operations and the statement of cash flows is largely unchanged. The standard is effective for fiscal years and interim periods beginning after December 15, 2018. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities to simplify the measurement, presentation, and disclosure of financial instruments. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, to simplify the subsequent measurement of inventory by replacing the current lower of cost and market test with a lower of cost and net realizable value test. The prospective application of this standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2014-15, Presentation of Financial Statements - Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity's management should evaluate whether there are conditions or events that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. This ASU will be effective for the annual reporting period ending after December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued a new revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

This new revenue standard is required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

3. Business acquisitions and development projects

(a) Acquisition of Empire

On February 9, 2016, the Company entered into an agreement and plan of merger pursuant to which, a subsidiary of Liberty Utilities Co. will merge with and into The Empire District Electric Company and its subsidiaries ("Empire"), and Empire will survive the merger and become a wholly owned indirect subsidiary of the Company. Empire is a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

Empire shareholders will receive U.S.$34.00 per common share in cash, which represents an aggregate purchase price of approximately U.S.$2,400,000, which includes the assumption of approximately U.S. $900,000 of debt.

The closing of the acquisition, which is expected to occur in early 2017, is subject to customary closing conditions, including the receipt of certain state and federal regulatory and government approvals. The Company has received all regulatory approvals for the transaction other than from the state of Kansas. On October 7, the Company filed a stipulation agreement reached with the Kansas Corporation Commission ("KCC") staff. for approval by Commissioners of the KCC. Final approval from the KCC is expected before the end of 2016,

On February 9, 2016, the Company obtained a $2,200,000 (U.S. $1,600,000) bridge financing commitment for the acquisition from a syndicate of banks (note 7).

On March 1, 2016, the Company issued $1,000,000 aggregate principal amount of 5.0% convertible unsecured subordinated debentures represented by installment receipts (the "convertible debentures" or the "Debenture Offering") and received the first installment of $333,000. On March 9, 2016, the underwriters exercised their option to purchase $150,000 additional convertible debentures. The convertible debentures are expected to convert to common shares of the Company upon the closing of the acquisition of Empire (note 10) at a conversion price of $10.60 per common share.

The Company converted the net proceeds received from the initial instalment of convertible debentures to U.S. dollar and has entered into foreign exchange contracts to buy an amount of U.S. $342,000 for $443,227 on January 31, 2017 in order to reduce the foreign currency risk related to the acquisition of Empire in U.S. dollars (note 21 (b)(iv)).

The Company has entered into forward contracts to reduce the interest rate risk related to the probable issuance of U.S. $500,000 bonds in relation to the long-term financing of the acquisition of Empire (note 21(b)(ii)).

3. Business acquisitions and development projects (continued)

(b) Acquisition of Park Water System

On January 8, 2016, the Company completed the acquisition of Western Water Holdings, LLC which is the parent company of Park Water Company ("Park Water System"), a regulated water distribution utility. Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and western Montana. The total purchase price for the Park Water System is U.S.$249,240, net of the debt assumed of U.S.$91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed through the unaudited interim consolidated statements of operations.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	1,984
Property, plant and equipment		345,254
Notes receivable		1,781
Goodwill		212,166
Regulatory assets		56,390
Other assets		185
Long-term debt		(146,727)
Regulatory liabilities		(3,758)
Pension and OPEB		(18,747)
Deferred income tax liability, net		(56,052)
Other liabilities		(39,825)
Total net assets acquired	$	352,651

The determination of the fair value of assets acquired and liabilities assumed is based upon management's preliminary estimates and certain assumptions. The Company has not completed the fair value measurements, particularly the relative fair value of the three utilities acquired. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. Insignificant changes to the initial allocation were recorded over the three and nine months ended September 30, 2016.

Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. On August 2, 2016 the Supreme Court of Montana upheld the District Court's decision that the City of Missoula can proceed with the condemnation of Mountain Water Company's assets. Upon taking possession of Mountain Water's assets, the compensation to be paid by the City of Missoula for such taking has been determined by the valuation commissioners to be U.S. $88,600. In addition, post-summons capital expenditures and attorney's fees as determined by the Montana court, property tax reimbursements and amounts in accordance with agreements entered into at the time of the Park Water acquisition should result in APUC receiving additional proceeds.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Park Water System assets is 40 years.

The Park Water System contributed revenue of $28,554 and $75,683 and net earnings of $11,386 and $22,821 to the Company's unaudited interim consolidated financial results for the three and nine months ended September 30, 2016.

The Transmission Group is upgrading the North Lake Tahoe Transmission System to enable eventual operation of the entire system at 120 kilovolts (KVs). The project is expected to improve the reliability of the system and ensure sufficient capacity to serve the existing customer base. The project will be separated into three phases the first of which, the rebuild of the 650 Line (10 miles) to 120kV was energized subsequent to quarter-end for a total cost of approximately U.S. $21,500.

4. Accounts receivable

Accounts receivable as of September 30, 2016 include unbilled revenue of $27,473 (December 31, 2015 - $49,002) from the Company's regulated utilities. Accounts receivable as of September 30, 2016 are presented net of allowance for doubtful accounts of $6,960 (December 31, 2015 - $7,966).

5. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the unaudited interim consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

In April 2016, the Granite State Electric System filed a general rate application. In June 2016, approval of a temporary rate increase of U.S. $2,355 was issued, effective July 1, 2016. A Final Order is expected in Q2 2017.

On April 22, 2016, the Arizona Corporation Commission approved a Final Order for the Black Mountain Sewer System of a U.S.$175 revenue increase effective May 1, 2016.

On February 18, 2016, the Georgia Public Service Commission approved a Final Order for the Peach State Gas System of a U.S.$2,725 revenue increase effective March 1, 2016.

On February 10, 2016, the New England Gas System received a Final Order from the Massachusetts Department of Public Utilities approving an annual revenue increase of U.S.$7,800 effective March 1, 2016.

5. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	September 30, 2016	December 31, 2015
Regulatory assets		
Environmental remediation	**$ 103,546**	$ 116,747
Pension and post-employment benefits	**73,872**	69,537
Commodity costs adjustment	**13,301**	7,643
Rate case costs	**7,786**	6,535
Rate adjustment mechanism	**33,175**	14,804
Debt premium	**24,800**	5,132
Taxes	**9,047**	5,927
Other	**20,886**	18,990
Total regulatory assets	**$ 286,413**	$ 245,315
Less current regulatory assets	**(47,298)**	(32,213)
Non-current regulatory assets	**$ 239,115**	$ 213,102
Regulatory liabilities		
Cost of removal	**$ 106,331**	$ 107,988
Rate-base offset	**21,267**	24,984
Commodity costs adjustment	**36,861**	32,423
Other	**18,128**	9,952
Total regulatory liabilities	**$ 182,587**	$ 175,347
Less current regulatory liabilities	**(51,136)**	(44,167)
Non-current regulatory liabilities	**$ 131,451**	$ 131,180

6. Long-term investments

Long-term investments consist of the following:

		September 30, 2016		December 31, 2015
Equity-method investees				
50% interest in Odell Wind Project Joint Venture (a)	**$**	**—**	$	42,287
50% interest in Deerfield Wind Project Joint Venture (b)		**7,285**		2,240
Red Lily (c)		**23,088**		—
Interests in natural gas pipeline developments (e)		**—**		5,623
Other		**2,917**		2,323
	$	**33,290**	$	52,473
Notes receivable				
Development loans (d)	**$**	**322,092**	$	96,924
Red Lily Senior loan Tranche 2, interest at 6.31% (c)		**—**		11,588
Red Lily Subordinated loan Tranche 1 and Tranche 2, interest at 12.5% (c)		**—**		6,565
Other		**5,888**		4,306
		327,980		119,383
Available-for-sale investment	**$**	**1,103**	$	2,946
Other investments	**$**	**2,602**	$	—
Total long-term investments	**$**	**364,975**	$	174,802

(a) Odell Wind Project Joint Venture

Up to September 15, 2016, the Company held a 50% equity interest in Odell SponsorCo LLC, which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Project") in the state of Minnesota. The interest capitalized during the three and nine months ended September 30, 2016 to the equity-method investment while the Odell Wind Project was under construction amounts to $490 and $3,331 (2015 - $1,623 and $3,150).

Construction was completed during the quarter and sale of power to the utility under the power purchase agreement started on July 29, 2016. On August 5, 2016, tax equity financing was provided to the Odell Wind Project by two U.S. financial institutions in the amount of U.S. $180,000.

On September 15, 2016, the Company acquired the remaining 50% interest in Odell SponsorCo LLC for U.S $26,500 and as a result, obtained control of the project. The Company accounted for the business combination using the acquisition method of accounting, which requires, that the fair values of assets acquired, liabilities assumed and non-controlling interest in the subsidiary, be recognized on the consolidated balance sheets as of the acquisition date. It further requires that preexisting relationships such as the existing development loan between the two parties (note 6(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. A net gain of $nil was recorded on acquisition.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

Working Capital	$	12,745
Property, plant and equipment		466,469
Asset retirement obligation		(4,813)
Deferred tax liability		(1,974)
Development loan from Algonquin Power Co (note 6(d))		(172,085)
Non-controlling interest (tax equity investors)		(237,157)
Net assets	$	63,185

6. Long-term investments (continued)

(a) Odell Wind Project Joint Venture (continued)

The determination of the fair value of assets acquired and liabilities assumed is based upon management's preliminary estimates and certain assumptions.

Property, plant and equipment are amortized using the unit-of-production method for applicable components, and straight-line method for all others. The overall weighted average useful life of the facility is 31 years

From July 29, 2016 to September 14, 2016 Odell contributed equity loss of $2,503. From September 15, 2016 Odell contributed revenue of $1,384 and net earnings of $495.

(b) Deerfield Wind Project Joint Venture

The Company owns a 50% equity interest in Deerfield Wind SponsorCo LLC (“Deerfield SponsorCo”), which indirectly owns a 149 MW construction-stage wind development project (“Deerfield Wind Project”) in the state of Michigan.

Upon the acquisition of the Deerfield Wind Project by Deerfield SponsorCo, the two members each contributed U.S.$1,000 to the capital of Deerfield SponsorCo. Subsequent to quarter-end, on October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S.$262,900 and a tax equity agreement was executed. Concurrently, each member contributed another U.S.$19,891 to the capital of Deerfield SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments at any time prior to the date that is 90 days following commencement of operations, which is expected in late 2016 or early 2017. The interest capitalized during the three and nine months ended September 30, 2016 to the investment while the Deerfield Wind Project is under construction amounts to $2,889 and $5,597 (2015 - $Nil and $Nil).

(c) Red Lily I

Up to April 12, 2016, the Red Lily I Partnership (the “Partnership”) was 100% owned by an independent investor. APUC provided operation and supervision services to the Red Lily I project, a 26.4 MW wind energy facility located in southeastern Saskatchewan.

The Company’s investment in Red Lily I as at January 1, 2016 was in the form of participation in a portion of the senior and subordinated debt facilities of the Partnership. On February 23, 2016, a second tranche of subordinated loan for an amount equal to $15,588 was advanced to the Partnership by the Company. The proceeds from this additional subordinated debt were used by the Partnership to repay Tranche 2 of the Partnership’s senior debt, including the Company’s portion.

Effective April 12, 2016, the Company exercised its option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its Tranche 1 and Tranche 2 subordinated loans. The carrying value of the Company's investment of $22,153 exceeds by $858 the Company's proportionate share of the Partnership's net assets as at that date. The difference is attributable to property, plant and equipment and is amortized over the assets' weighted average useful lives.

Due to certain participating rights being held by the minority investor, APUC is deemed under U.S. GAAP, to not have control over the Partnership. As a result, the Company accounts for the Partnership using the equity method. Red Lily I contributed equity income of $935 to the Company's unaudited interim consolidated financial results from acquisition to September 30, 2016.

(d) Development loans

During the nine months ended September 30, 2016, the Company advanced U.S. $238,272 to the Deerfield Wind Project for total advances of U.S. $245,553 and credit support in the amount of U.S. $1,699. Concurrent with the construction financing obtained by the Deerfield Wind Project from a third-party subsequent to quarter-end (note 6 (b)), U.S.$19,891 of the development loan receivable by the Company was contributed to the capital of Deerfield SponsorCo while the balance was repaid by Deerfield Wind Project. The Company used the funds received to repay that portion of its revolving credit facility.

Following acquisition of control of Odell SponsorCo LLC (note 6(a)) on September 15, 2016, amounts advanced to the Odell Wind Project are eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in other comprehensive income effective August 5, 2016.

6. Long-term investments (continued)

(e) Natural gas pipeline developments

During the nine months ended September 30, 2016, APUC wrote off an amount of $6,367 representing the total value of its equity interest in the natural gas development projects, as both projects have been canceled by the developer.

7. Long-term debt

Long-term debt consists of the following:

	September 30, 2016	December 31, 2015
Revolving Credit Facilities	**$ 182,244**	$ 27,300
Term Facilities	**337,667**	—
Unsecured Notes	**1,316,128**	1,388,805
Secured Notes	**56,627**	38,560
First Mortgage Bonds	**129,631**	32,130
	$ 2,022,297	$ 1,486,795
Less: current portion	**(75,628)**	(8,945)
	$ 1,946,669	$ 1,477,850

Long-term debt issued at a subsidiary level relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Subsidiary level long term debt, whether or not collaterized have certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

On January, 4, 2016, the Company entered into a U.S.$235,000 term credit facility with two U.S. banks. The term credit facility is available for acquisitions and general corporate purposes and matures on July 5, 2017. Subsequent to the quarter, on November 9, 2016, the Company extended the maturity date by one year to July 5, 2018.

Subsequent to the quarter, on October 21, 2016, the Company extended the maturity date by one year to October 30, 2017.

The Company also has a senior unsecured revolving credit of $65,000 which was undrawn as at September 30, 2016. During the first quarter, the maturity of the facility was extended by one year. The facility now matures on November 19, 2017 and is subject to customary covenants.

On February 9, 2016, in connection with the acquisition of Empire (note 3 (a)), the Company obtained U.S.$1,600,000 in bridge financing commitments from a syndicate of banks. The non-revolving term credit facilities are comprised of a U.S.$1,065,000 debt bridge facility, repayable in full on the first anniversary following its advance, and a U.S. $535,000 equity bridge facility repayable in full on the first anniversary following its advance. On March 1, 2016, upon issuing the convertible debentures (note 10) and receiving the First Instalment, the Company reduced its bridge commitments by U.S. $263,600. The effective interest expense recorded for the three and nine months ended September 30, 2016 is $2,500 and $5,673, respectively.

On January 8, 2016, the Company assumed U.S. $91,750 of short and long term debt as part of the Park Water System acquisition. Shortly after the closing of the acquisition, the Park Water System repaid and closed U.S. $4,250 of debt outstanding under its revolving credit facilities. The remaining U.S. $87,500 of debt is secured by a first mortgage indenture and consists of a U.S. $22,500 a non-revolving term credit facility and six tranches of first mortgage bonds. The term credit facility bears a variable interest rate based on LIBOR plus a credit spread and matures in 2019 but is repayable on demand without penalty. The First Mortgage bonds have maturities ranging between 2020 and 2043 with coupons ranging from 4.53% to 8.82%.

8. Pension and other post-employment benefits

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of operating expenses in the unaudited interim consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the unaudited interim consolidated statements of operations from the date of acquisition.

	Pension benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Service cost	**$ 2,132**	$ 1,595	**$ 6,482**	$ 4,729
Interest cost	**3,150**	2,420	**9,578**	6,946
Expected return on plan assets	**(3,419)**	(3,129)	**(10,394)**	(8,854)
Amortization of net actuarial loss	**742**	323	**2,257**	923
Amortization of prior service credits	**(188)**	(161)	**(572)**	(324)
Net change in regulatory asset/liability	**1,085**	1,151	**3,298**	3,358
Net benefit cost	**$ 3,502**	$ 2,199	**$ 10,649**	$ 6,778

	OPEB			
	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Service cost	**$ 796**	$ 758	**$ 2,419**	$ 2,191
Interest cost	**904**	697	**2,751**	2,015
Expected return on plan assets	**(298)**	(199)	**(906)**	(576)
Amortization of net actuarial loss	**136**	35	**414**	100
Amortization of prior service credits	**(453)**	—	**(1,377)**	—
Net change in regulatory asset/liability	**246**	272	**749**	780
Net benefit cost	**$ 1,331**	$ 1,563	**$ 4,050**	$ 4,510

During the nine months ended September 30, 2016, the Company permanently froze the accrual of retirement benefits for some participants under existing plans, effective December 31, 2016. Subsequent to the effective date, these employees will begin accruing benefits under the Company's cash balance plan. The plan amendments resulted in a decrease to the projected benefit obligation of U.S. $2,217 which is recorded as a prior service credit in other comprehensive income ("OCI"). In conjunction with the plan amendment, the assets and projected benefit obligations of amended plans were revalued at the closest month-end date of March 31, 2016 which resulted in an actuarial loss of U.S. $8,204 recorded in OCI.

9. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	September 30, 2016	December 31, 2015
Advances in aid of construction	**$ 109,068**	$ 92,285
Environmental remediation obligation	**63,271**	71,529
Asset retirement obligations	**23,962**	17,799
Customer deposits	**14,165**	15,074
Deferred income	**6,499**	13,682
Deferred credits	**23,025**	24,110
Other	**42,348**	25,277
	282,338	259,756
Less current portion	**(27,887)**	(36,621)
	$ 254,451	$ 223,135

10. Convertible Unsecured Subordinated Debentures

Maturity date		March 31, 2026
Interest rate		5.00%
Conversion price per share	$	10.60
Carrying value at December 31, 2015	$	—
Receipt of initial Instalment, net of deferred financing costs		357,880
Amortization of deferred financing costs		626
Carrying value at September 30, 2016	$	358,506
Face value at September 30, 2016	$	382,950

On March 1, 2016, the Company completed the sale of $1,000,000 aggregate principal amount of 5.0% convertible debentures. On March 9, 2016, the underwriters exercised their option to purchase $150,000 additional convertible debentures bringing the total amount of the offering to $1,150,000.

The convertible debentures were sold on an instalment basis at a price of $1,000 per debenture, of which $333 was paid on closing of the Debenture Offering and the remaining $667 (the "Final Instalment") is payable on a date ("Final Instalment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire. The proceeds received from the initial instalment were $382,950. The Company incurred deferred financing costs of $25,070, which are being amortized to interest expense over 10 years, the contractual term of the convertible debentures, using the effective interest rate method.

The convertible debentures represented by the initial instalment receipt are classified as a non-current liability on the unaudited interim consolidated balance sheets as settlement in cash is not expected to occur within 12 months. The convertible debentures mature on March 31, 2026 and bear interest at an annual rate of 5% per $1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate will be 0%. If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of convertible debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the convertible debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering.

10. Convertible Unsecured Subordinated Debentures (continued)

Based on the first instalment of $333 per $1,000 principal amount of convertible debentures and the expectation that the Final Instalment Date will occur on a day that is after the first anniversary of the closing of the Debenture Offering, the effective annual yield to and including the Final Instalment Date is 15%, and the effective annual yield thereafter is 0%. The effective interest expense recorded for the three and nine months ended September 30, 2016 is $14,494 and $33,713.

At the option of the holders and provided that payment of the Final Instalment has been made, each Debenture will be convertible into common shares of the Company at any time after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $10.60 per common share.

Prior to the Final Instalment Date, the convertible debentures may not be redeemed by the Company, except that convertible debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Empire will not be satisfied; (ii) termination of the acquisition agreement; and (iii) September 11, 2017 if notice of the Final Instalment Date has not been given to holders on or before September 8, 2017. Upon any such redemption, the Company will pay for each Debenture $333 plus accrued and unpaid interest to the holder of the instalment receipt. In addition, after the Final Instalment Date, any convertible debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

11. Shareholders' capital

(a) Common shares

Number of common shares:

	2016
Common shares, beginning of year	**255,869,419**
Issuance of common shares upon conversion of subscription receipts	**12,938,457**
Issuance of common shares upon exercise of share options, net of withholding taxes	**2,720,980**
Issuance of shares under the dividend reinvestment and employee share compensation plans	**1,785,569**
Common shares, end of period	**273,314,425**

(b) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 from the issuance to Emera Inc. ("Emera") of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo investment (note 6(a)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 661,693 additional common shares in lieu of dividends declared during the holding period.

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(b)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 252,011 additional common shares in lieu of dividends declared during the holding period.

11. Shareholders' capital (continued)

(c) Share-based compensation

During the nine months ended September 30, 2016, the Board of Directors of APUC (the "Board") approved the grant of 2,596,025 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $10.86, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2017, 2018, and 2019. Options may be exercised up to eight years following the date of grant.

The following assumptions were used in determining the fair value of share options granted:

Risk-free interest rate		**0.9%**
Expected volatility		**23.0%**
Expected dividend yield		**4.5%**
Expected life (years)		**5.5**
Weighted average grant date fair value per option	**$**	**1.26**

During the first quarter, executives of the Company exercised 3,715,663 stock options at a weighted average exercise price of $5.25 in exchange for 2,720,980 common shares issued from treasury and 994,683 shares withheld as payment in lieu of minimum tax withholdings.

In June 2016, 190,645 Performance Share Units ("PSU") were granted to executives and employees of the Company. The PSUs vest on January 1, 2019. During the second quarter, the Company settled 173,441 PSU by issuing 87,361 shares from treasury, with the balance withheld as payment in lieu of minimum tax withholdings.

During the nine months ended September 30, 2016, 49,605 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their Directors' fee in the form of DSUs.

For the three and nine months ended September 30, 2016, APUC recorded $1,581 and $4,073 (2015 - $1,572 and $3,662) in total share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the unaudited interim consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of September 30, 2016, total unrecognized compensation costs related to non-vested options and PSUs were $4,033 and $2,749, respectively, and are expected to be recognized over a period of 1.93 and 1.86 years, respectively.

12. Accumulated other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2015	$ 32,496	$ 23,164	$ 1	$ (21,448)	$ 34,213
OCI (loss) before reclassifications	228,861	21,896	(73)	6,487	257,171
Amounts reclassified	—	(5,731)	—	1,084	(4,647)
Net current period OCI	228,861	16,165	(73)	7,571	252,524
Balance, December 31, 2015	$ 261,357	$ 39,329	$ (72)	$ (13,877)	$ 286,737
OCI before reclassifications	(108,484)	1,847	20	(4,152)	(110,769)
Amounts reclassified	—	(7,995)	—	620	(7,375)
Net current period OCI	$(108,484)	$ (6,148)	$ 20	$ (3,532)	$ (118,144)
Balance, September 30, 2016	$ 152,873	$ 33,181	$ (52)	$ (17,409)	$ 168,593

Amounts reclassified from AOCI for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected administrative expenses.

13. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividend on its commons shares in U.S. dollars. Dividends declared in Canadian equivalent dollars during the three and nine months ended September 30 were as follows:

	Three months ended September 30,			
	2016		2015	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 37,735**	**$ 0.1377**	$ 32,554	$ 0.1289
Series A preferred shares	**$ 1,350**	**$ 0.2813**	$ 1,350	$ 0.2813
Series D preferred shares	**$ 1,250**	**$ 0.3125**	$ 1,250	$ 0.3125

	Nine months ended September 30,			
	2016		2015	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 109,937**	**$ 0.4025**	$ 90,604	$ 0.3600
Series A preferred shares	**$ 4,050**	**$ 0.8438**	$ 4,050	$ 0.8438
Series D preferred shares	**$ 3,750**	**$ 0.9375**	$ 3,750	$ 0.9375

14. Related party transactions

Emera Inc.

A member of the Board of APUC is an executive at Emera. For the three and nine months ended September 30, 2016, the Company's energy services business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. $3,095 and $7,951 (2015 - U.S. $1,717 and $4,754). For the three and nine months ended September 30, 2016, Liberty Utilities purchased natural gas amounting to U.S. $534 and $2,762 (2015 - U.S. $83 and $1,422) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction. On May 13, 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The total cost of the contract is estimated at $8,558 and is expected to be completed in 2016. The contract followed a market based request for proposal process.

There was U.S. $64 included in accruals for the nine months ended September 30, 2016 (December 31, 2015 - U.S. $491) related to these transactions.

Equity-method investments

The Company provides administrative and operating services to its equity-method investees, earns royalty revenue and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $893 and $2,510 (2015 - $532 and $1,477) during the three and nine months ended September 30, 2016.

Senior Executives

Ian Robertson and Chris Jarratt are senior executives of APUC (collectively "Senior Executives").

The Company owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Trafalgar went into default under its debt obligations and an entity partially and indirectly owned by Senior Executives (the "Related Entity"), moved to foreclose on the assets on behalf of the Company. Subsequent to the foreclosure action, Trafalgar went into bankruptcy. APUC and the Related Entity have jointly pursued litigation and bankruptcy proceedings with Trafalgar since 2002.

In 2003 and 2004, the Company reimbursed the Related Entity $1,000 of the approximately $2,000 in third-party legal fees it had initially funded and APUC agreed to fund future legal fees and other liabilities. It was agreed that any net proceeds from the litigation and bankruptcy proceedings would be shared proportionally to the quantum of net legal costs funded by each party. On June 30, 2016, the Company received U.S. $10,083 in proceeds from the settlement of this matter and, subsequent to quarter-end, paid U.S. $2,900 to the Related Entity as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6,600 was recorded in the second quarter.

15. Non-controlling interests

Net loss attributable to non-controlling interests consists of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
Net loss attributable to Class A partnership units	**(5,189)**	(4,501)	**(27,381)**	(21,372)
Other net earnings attributable to non-controlling interests	**2,165**	259	**4,258**	1,321
Total net loss attributable to non-controlling interests	**$ (3,024)**	$ (4,242)	**$ (23,123)**	$ (20,051)

16. Income taxes

For the nine months ended September 30, 2016, the Company's overall effective tax rate was different from the statutory rate of 26.50% (2015 - 26.50%) due primarily to higher tax rates in U.S. subsidiaries, non-controlling interest partner's tax expenses, inter-corporate dividends and non-deductible expenses.

On September 16, 2016, Revenu Québec issued a notice of assessment approving the Company's Canadian renewable and conservation expense ("CRCE") refundable tax credit claim for the St Damase wind facility in the amount of $14,086. The Company received the tax credit in cash on October 6, 2016. The tax credit together with interest received was recorded, net of related costs, as a reduction of the related assets in property, plant, and equipment.

17. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and subscription receipts outstanding. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share for the three and nine months ended September 30 are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2016	**2015**	**2016**	**2015**
Net earnings attributable to shareholders of APUC	**$ 17,745**	$ 16,454	**$ 84,578**	$ 79,492
Series A Preferred shares dividend	**1,350**	1,350	**4,050**	4,050
Series D Preferred shares dividend	**1,250**	1,250	**3,750**	3,750
Net earnings attributable to common shareholders of APUC	**$ 15,145**	$ 13,854	**$ 76,778**	$ 71,692
Discontinued operations	**—**	(241)	**—**	(954)
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	**$ 15,145**	$ 14,095	**$ 76,778**	$ 72,646
Weighted average number of shares				
Basic	**273,202,368**	252,352,179	**271,120,426**	251,528,726
Effect of dilutive securities	**2,376,823**	3,552,824	**2,433,527**	3,392,848
Diluted	**275,579,191**	255,905,003	**273,553,953**	254,921,574

The shares potentially issuable, for the three and nine months ended September 30, 2016, as a result of 108,424 and 1,417,500 share options (2015 - 1,608,974 and 1,608,974) are excluded from this calculation as they are anti-dilutive. The shares contingently issuable as a result of 1,150,000 convertible debentures are not included in diluted earnings per share until the conditions for closing the Empire acquisition are met.

18. Segmented information

The Company's management's reporting structure is aligned under three business units: Generation, Transmission and Distribution.

Generation, owns or has interests in hydroelectric, solar, wind power facilities and co-generation. Distribution operates electric, natural gas and water distribution utilities. Finally, Transmission invests in rate regulated electric transmission and natural gas pipeline systems. The Transmission segment is not yet significant and as a result is not presented separately in the tables below but grouped within Corporate.

18. Segmented information (continued)

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship and acquisition costs are not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these segments are reflected in the tables below.

	Three months ended September 30, 2016			
	Generation	Distribution	Corporate	Total
Revenue	$ 60,730	$ 160,547	$ —	$ 221,277
Fuel, power and water purchased	6,018	41,147	—	47,165
Net revenue	54,712	119,400	—	174,112
Operating expenses	17,386	62,610	353	80,349
Administrative expenses	4,863	6,902	306	12,071
Depreciation and amortization	15,385	23,175	1,173	39,733
Gain on foreign exchange	—	—	(3,355)	(3,355)
Operating income from continuing operations	17,078	26,713	1,523	45,314
Interest expense	5,123	12,322	17,322	34,767
Interest, dividend, equity and other income	561	(1,324)	(742)	(1,505)
Other expense (gain)	(1,684)	(4,926)	2,146	(4,464)
Earnings (loss) before income taxes	$ 13,078	$ 20,641	$ (17,203)	$ 16,516
Capital expenditures	25,074	61,940	5,243	92,257

	Three months ended September 30, 2015			
	Generation	Distribution	Corporate	Total
Revenue	$ 52,923	$ 136,658	$ —	$ 189,581
Fuel, power and water purchased	5,270	39,267	—	44,537
Net revenue	47,653	97,391	—	145,044
Operating expenses	17,037	55,919	265	73,221
Administrative expenses	3,560	4,774	148	8,482
Depreciation and amortization	14,417	19,489	767	34,673
Gain on foreign exchange	—	—	(1,635)	(1,635)
Operating income from continuing operations	12,639	17,209	455	30,303
Interest expense	5,647	9,358	402	15,407
Interest, dividend and other income	(447)	(980)	(917)	(2,344)
Other gain	17	1,460	232	1,709
Earnings before income taxes	$ 7,422	$ 7,371	$ 738	$ 15,531
Capital expenditures	22,304	52,556	5,171	80,031

18. Segmented information (continued)

	Nine months ended September 30, 2016			
	Generation	Distribution	Corporate	Total
Revenue	$ 192,049	$ 593,735	$ —	$ 785,784
Fuel, power and water purchased	15,042	190,392	—	205,434
Net revenue	177,007	403,343	—	580,350
Operating expenses	52,167	191,616	948	244,731
Administrative expenses	13,911	18,380	1,573	33,864
Depreciation and amortization	55,770	75,395	3,102	134,267
Gain on foreign exchange	—	—	(1,782)	(1,782)
Operating income (loss) from continuing operations	55,159	117,952	(3,841)	169,270
Interest expense	14,878	37,427	40,592	92,897
Interest, dividend, equity and other income	(160)	(3,849)	(2,426)	(6,435)
Other expense (gain)	(14,519)	(4,525)	14,766	(4,278)
Earnings (loss) before income taxes	$ 54,960	$ 88,899	$ (56,773)	$ 87,086
Property, plant and equipment	2,306,390	2,180,189	97,930	4,584,509
Equity-method investees	30,540	893	1,857	33,290
Total assets	2,894,963	2,971,964	153,901	6,020,828
Capital expenditures	86,313	133,255	14,390	233,958

	Nine months ended September 30, 2015			
	Generation	Distribution	Corporate	Total
Revenue	$ 174,765	$ 592,828	$ —	$ 767,593
Fuel, power and water purchased	22,645	269,048	—	291,693
Net revenue	152,120	323,780	—	475,900
Operating expenses	48,602	161,483	927	211,012
Administrative expenses	11,720	15,347	393	27,460
Depreciation and amortization	47,964	57,460	2,467	107,891
Gain on foreign exchange	—	—	(2,921)	(2,921)
Operating income (loss) from continuing operations	43,834	89,490	(866)	132,458
Interest expense	21,345	26,010	1,212	48,567
Interest, dividend and other income	(1,458)	(2,910)	(1,961)	(6,329)
Other expense (gain)	(4,445)	1,712	606	(2,127)
Earnings (loss) before income taxes	$ 28,392	$ 64,678	$ (723)	$ 92,347
Capital expenditures	51,165	100,998	9,714	161,877
	December 31, 2015			
Property, plant and equipment	1,899,103	1,890,353	87,714	3,877,170
Equity-method investees	44,638	769	7,066	52,473
Total assets	2,345,905	2,508,267	137,553	4,991,725

19. Commitments, litigation and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the unaudited interim consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

On October 21, 2011, the Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the Government of Quebec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,940. In 2012, the Company paid an amount of $1,884 to the Government of Quebec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

(b) Litigation

In December 2012, Algonquin Power (Long Sault) Partnership and its non-controlling equity members ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of power purchase agreements ("PPAs") between non-utility generators and the OEFC, in relation to the use of the global adjustment as a price escalator.

As at September 13, 2015, the Ontario Courts have ruled that the methodology that the OEFC used from January 1, 2011, onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decisions further require the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. OEFC has sought leave to appeal to the Supreme Court of Canada.

In September 2016, the OEFC and Long Sault agreed on a retroactive adjustment of $5,083 which the Company recorded as non-regulated energy sales in the third quarter. The retroactive payment was received on October 21, 2016.

19. Commitments, litigation and contingencies (continued)

(c) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 6, the following significant commitments exist as of September 30, 2016

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Power purchase	$ 51,614	$ 35,008	$ 35,193	$ 36,458	$ 11,045	$ —	$ 169,318
Gas supply and service agreements	62,472	47,413	36,508	33,836	19,020	66,426	265,675
Service agreements	39,905	40,766	40,799	44,812	44,953	506,181	717,416
Capital projects	213,218	29,734	17,670	368	68	17	261,075
Operating leases	7,535	7,211	6,910	6,730	6,811	130,113	165,310
Total	$374,744	$160,132	$137,080	$122,204	$ 81,897	$702,737	$1,578,794

20. Non-cash operating items

The changes in non-cash operating items consist of the following:

	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Accounts receivable	**$ 5,126**	$ 9,752	**$ 58,345**	$ 43,995
Natural gas in storage	**(8,033)**	(11,152)	**5,084**	3,716
Supplies and consumable inventory	**(935)**	(1,478)	**(430)**	(3,272)
Income taxes receivable	**(787)**	216	**910**	58
Prepaid expenses	**4,282**	4,299	**(1,551)**	(4,119)
Accounts payable	**25**	(956)	**(40,424)**	(49,395)
Accrued liabilities	**(15,356)**	27,757	**(54,877)**	(55,343)
Current income tax liability	**929**	1,321	**(3,972)**	950
Net regulatory assets and liabilities	**(3,976)**	(6,828)	**(6,059)**	34,524
	$ (18,725)	**$ 22,931**	**$ (42,974)**	$ (28,886)

21. Financial instruments

(a) Fair value of financial instruments

September 30, 2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 327,980	$ 333,539	$ —	$ 333,539	$ —
Derivative financial instruments[1]:					
Energy contracts designated as a cash flow hedge	87,389	87,389	—	—	87,389
Currency forward contract not designated as a hedge	4,897	4,897	—	4,897	—
Commodity contracts for regulated operations	106	106	—	106	—
Total derivative financial instruments	92,392	92,392	—	5,003	87,389
Total financial assets	$ 420,372	$ 425,931	$ —	$ 338,542	$ 87,389
Long-term debt	$ 2,022,297	$ 2,163,781	$ 519,701	$ 1,644,080	$ —
Convertible debentures	358,506	486,450	486,450	—	—
Preferred shares, Series C	18,468	18,933	—	18,933	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	89,572	89,572	—	89,572	—
Interest rate swap designated as a hedge	22,832	22,832	—	22,832	—
Currency forward contract not designated as a hedge	—	—	—	—	—
Commodity contracts for regulated operations	368	368	—	368	—
Total derivative financial instruments	112,772	112,772	—	112,772	—
Total financial liabilities	$ 2,512,043	$ 2,781,936	$1,006,151	$ 1,775,785	$ —

(1) Balance of $263 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

21. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

December 31, 2015	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 119,383	$ 126,468	$ —	$ 126,468	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	88,357	88,357	—	—	88,357
Commodity contracts for regulatory operations	4	4	—	4	—
Total derivative financial instruments	88,361	88,361	—	4	88,357
Total financial assets	$ 207,744	$ 214,829	$ —	$ 126,472	$ 88,357
Long-term debt	$1,486,795	$1,547,346	$ 511,829	$1,035,517	$ —
Preferred shares, Series C	18,527	17,303	—	17,303	—
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	446	446	—	—	446
Cross-currency swap designated as a net investment hedge	101,559	101,559	—	101,559	—
Interest rate swaps designated as a hedge	9,659	9,659	—	9,659	
Currency forward contract not designated as a hedge	1,918	1,918	—	1,918	—
Commodity contracts for regulated operations	1,676	1,676	—	1,676	—
Total derivative financial instruments	115,258	115,258	—	114,812	446
Total financial liabilities	$1,620,580	$1,679,907	$ 511,829	$1,167,632	$ 446

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of September 30, 2016 and December 31, 2015 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $20.65 to $107.11 with a weighted average of $36.62 as of September 30, 2016.

21. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 21(b)(ii) and 21(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the three or nine months ended September 30, 2016 and 2015.

(b) Derivative instruments

Derivative instruments are recognized on the unaudited interim consolidated balance sheets as either assets or liabilities and measured at fair value at each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sale prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

	2016
Financial contracts: Gas swaps	821,531
Gas options	1,180,920
	2,002,451

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the unaudited interim consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 5). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the unaudited interim consolidated balance sheets:

	September 30, 2016	December 31, 2015
Regulatory assets:		
Gas swap contracts	U.S. **$ 68**	U.S. $ 1,058
Gas option contracts	U.S. **$ 211**	U.S. $ 154
Regulatory liabilities:		
Gas swap contracts	U.S. **$ 75**	U.S. $ 3
Gas option contracts	U.S. **$ 5**	U.S. $ —

21. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities and at one of its hydro facilities no longer subject to a power purchase agreement by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Pay floating price (per MW-hr)
10,968	December 2016	$	68.56	AESO
718,389	December 2022	U.S. $	42.81	PJM Western HUB
3,075,266	December 2022	U.S. $	30.25	NI HUB
3,762,879	December 2027	U.S. $	36.46	ERCOT North HUB

Subsequent to quarter-end, on October 25, 2016, the Company entered into forward contracts to purchase U.S. $250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500,000 bonds in relation to the acquisition of Empire (note 3(a)).

On November 14, 2014, the Company entered into a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a loss of $1,758 and $13,174 for the three and nine months ended September 30, 2016 (2015 - loss of $5,108 and $4,671), which is recorded in OCI.

The following table summarizes OCI attributable to derivative financial instruments designated as a cash flow hedge:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
Effective portion of cash flow hedge, loss (gain)	**$ (17,052)**	$ 11,981	**$ 1,877**	$ 21,843
Amortization of cash flow hedge	**(14)**	(10)	**(30)**	(27)
Gain reclassified from AOCI	**(2,723)**	(1,178)	**(7,995)**	(3,083)
OCI attributable to shareholders of APUC	**$ (19,789)**	$ 10,793	**$ (6,148)**	$ 18,733

The Company expects $11,738 of unrealized gains currently in AOCI to be reclassified into non-regulated energy sales within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major Canadian and U.S. financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company designates the amounts drawn on the Generation Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from Odell and Deerfield Wind SponsorCo as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency loss of $Nil and $Nil for the three and nine months ended September 30, 2016 (2015 - $Nil and $Nil) was recorded in OCI.

21. Financial instruments (continued)

(b) Derivative instruments (continued)

(iii) Foreign exchange hedge of net investment in foreign operation (continued)

Concurrent with its $150,000 and $200,000 notes offerings in December 2012 and January 2014, respectively, the Company entered into cross currency swaps, coterminous with the notes, to effectively convert the Canadian dollar denominated offering into U.S. dollars.

The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. For the three and nine months ended September 30, 2016 a loss of $5,767 and gain of $9,020 (2015 - loss of $29,666 and$50,162) was recorded in OCI.

(iv) Other derivative and financial instruments

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short-term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 21(b)(ii)).

The Company was party to an interest rate swap whereby the Company paid a fixed interest rate of 4.47% on a notional amount of $58,791 and received floating interest at 90 day CDOR. The swap expired on September 2015. As of December 31, 2015, the estimated fair value of the interest rate swap was a liability of Nil. This interest rate swap was not accounted for as a hedge.

The Company is exposed to foreign exchange fluctuations related to U.S dollar denominated development loans from projects accounted for as equity investments (note 6) and other commitments. This risk was mitigated through the use of currency forward contracts to sell a net amount of U.S. $38,400 for $47,225 between July 29, 2016 and Sept 29, 2016. As of September 30, 2016, these instruments had settled. These currency forward contracts were not accounted for as a hedge.

The Company is exposed to foreign exchange fluctuations related to the expected acquisition of the Empire shares denominated in U.S dollar (note 3(a)). This risk is mitigated through the conversion to U.S. dollars of $359,950 from the proceeds received on the initial instalment of convertible unsecured subordinated debentures (note 10) and the use of a currency forward contract to buy an amount of U.S. $330,000 for $427,622 on January 31, 2017. As of September 30, 2016, the estimated fair value of the instrument was an asset of $4,897. This currency forward contract was not accounted for as a hedge. Subsequent to quarter-end, the Company acquired an additional currency forward contract to buy an amount of U.S. $12,000 for $15,605 on January 31, 2017.

For derivatives that are not designated as hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the unaudited interim consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

21. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivative and financial instruments (continued)

	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Change in unrealized loss (gain) on derivative financial instruments:				
Interest rate swaps	**$ —**	$ (511)	**$ —**	$ (1,383)
Energy derivative contracts	**—**	138	**(426)**	626
Currency forward contract	**(7,261)**	—	**(6,843)**	—
Total change in unrealized gain on derivative financial instruments	**$ (7,261)**	$ (373)	**$ (7,269)**	$ (757)
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps	**—**	515	**—**	1,498
Energy derivative contracts	**—**	42	**941**	(593)
Currency forward contract	**4,229**	—	**(1,371)**	—
Total realized loss (gain) on derivative financial instruments	**$ 4,229**	$ 557	**$ (430)**	$ 905
Loss (gain) on derivative financial instruments not accounted for as hedges	**(3,032)**	184	**(7,699)**	148
Ineffective portion of derivative financial instruments accounted for as hedges	**507**	37	**1,509**	(2,384)
	$ (2,525)	$ 221	**$ (6,190)**	$ (2,236)
Amounts recognized in the unaudited interim consolidated statements of operations consist of:				
Loss (gain) on derivative financial instruments	**$ (4,419)**	$ 221	**$ (2,902)**	$ (2,236)
Loss (gain) on foreign exchange	**$ 1,893**	$ —	**$ (3,289)**	$ —
	$ (2,525)	$ 221	**$ (6,190)**	$ (2,236)

Effective May 1, 2016, the Company entered into a weather derivative contract as an economic hedge for revenue from its St. Leon I wind powered generating facility in the event the wind resource availability falls below a normal range. Non-exchange-traded options are accounted for using the intrinsic method. Changes in the intrinsic value of $158 in 2016 is reflected in non-regulated energy sales in our interim unaudited consolidated statement of operations. Premiums paid related to these weather derivative agreements are expensed over each respective contract period.

22. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current period.

NOTES

NOTES

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