

Q1
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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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 three months ended March 31, 2016. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's unaudited interim consolidated financial statements for the three months ended March 31, 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 Annual Information Form.

This MD&A is based on information available to management as of May 12, 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 and 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. 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 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. 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 commodities 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. Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's 2015 Annual Information Form.

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 a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

APUC's current quarterly dividend to shareholders is U.S. \$0.1059 per common share or U.S. \$0.4235 per common share on an annual basis. Based on exchange rates as at May 12, 2016 the quarterly dividend is equivalent to Cdn. \$0.1361 per common share or Cdn. \$0.5445 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 and mitigate the impact of fluctuations in foreign exchange rates. 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 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 in North America.

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, 700 MW, 30 MW, and 335 MW respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group also has a portfolio of development projects that between 2016 and 2018 will add approximately 711 MW of generation capacity from wind and solar powered generating facilities with an average contract life of 21 years.

Distribution Business Group

The Distribution Group operates diversified rate 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.

Major Highlights

Corporate Highlights

Annual dividend increased from U.S. \$0.3850 to U.S. \$0.4235 and Declaration of Canadian equivalent second quarter dividend of Cdn. \$0.1361 (U.S. \$0.1059) per Common Share

APUC targets a 10% annual growth in dividends payable to shareholders underpinned by increases in earnings and cashflow. Management believes that the increase in dividends is consistent with APUC's stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation.

APUC completed the acquisition of Park Water Company in the first quarter and announced its agreement to acquire The Empire District Electric Company (see below). In addition, it has completed construction of new electric generating stations and has a number of electric generating stations in construction and under development. Collectively these growth initiatives have continued to raise the growth profile of the company. The increased earnings and cash flows are apparent in the first quarter results and support an increase in the dividend to shareholders. As a result, on May 12, 2016, the Board approved a dividend increase of U.S. \$0.0385 per common share annually, bringing the total annual dividend to U.S. \$0.4235 per common share, an increase of 10% over the previous dividend rate.

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

	Q3 2015	Q4 2015	Q1 2016	Q2 2016	Total
U.S. dollar Dividend	\$0.0963	\$0.0963	\$0.0963	\$0.1059	\$0.3948
Canadian dollar equivalent	\$0.1289	\$0.1267	\$0.1287	\$0.1361	\$0.5204

Strong First Quarter Operating results

APUC recorded strong first quarter 2016 results. Adjusted EBITDA grew from \$114.5 million in the first quarter of 2015 to \$147.9 million in the first quarter of 2016, an increase of 29%. Adjusted funds from operations grew from \$101.0 million in the first quarter of 2015 to \$121.8 million in the first quarter of 2016, an increase of 21%. Adjusted Earnings per Share grew from \$0.17 in the first quarter of 2015 to \$0.21 in the first quarter of 2016, an increase of 24%.

Pending Acquisition of The Empire District Electric Company

On February 9, 2016 APUC announced that through a wholly owned subsidiary it has entered into an agreement and plan of merger pursuant to which it will acquire The Empire District Electric Company ("Empire") (NYSE:EDE) and its subsidiaries (the "Acquisition").

Empire is a Joplin, Missouri based regulated utility and electric generation company. Its regulated utilities provide regulated electric, gas (through its wholly-owned subsidiary The Empire District Gas Company), and water utility services, collectively serving approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. Empire also has an electric generating business with 1,326 MW of generating capacity.

Under the terms of the all-cash transaction, which has been unanimously approved by the Board of Directors of each company, Empire's shareholders will receive U.S. \$34.00 per common share (the "Purchase Price"), representing an aggregate purchase price of U.S. \$2.4 billion, including the assumption of approximately U.S. \$0.9 billion of debt as of September 30, 2015. The Purchase Price represents a 21% premium to the closing price on February 8, 2016.

Closing of the Acquisition is subject to customary closing conditions, including the approval of Empire's common shareholders, and the 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. The Transaction is expected to close early in 2017.

APUC expects the Acquisition will be accretive to earnings per common share in the first full year following closing and approximately 7% - 9% accretive to APUC's net earnings per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. APUC also expects that the Acquisition will be approximately 12% - 14% accretive to Adjusted funds from operations per Common Share over a three-year period following closing, excluding one-time Acquisition-Related Expenses, and assuming a stable currency exchange environment. The Acquisition is expected to remain accretive to APUC's net earnings and cash from operating activities notwithstanding a scenario in which the Canadian dollar strengthens.

The Acquisition adds a large profitable regulated distribution and generation business, increasing APUC's scale, diversity of customers, and geographies of service. APUC believes the increased contribution from regulated operations will further enhance the stability and predictability of Adjusted EBITDA, net earnings, and quality of cash flows.

Update on acquisition approval process

Empire has set May 2, 2016 as the record date for determining eligibility to vote on the Agreement and Plan of Merger and is expected to hold a special Shareholder's Meeting on June 16, 2016 for the purpose of voting on the Agreement and Plan of Merger.

Applications to four state commissions (OK, KS, MO, AR) 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 District Electric. 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 District Electric by Liberty Utilities Co. The order approves the acquisition as filed, without any material conditions.

\$1 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

On February 9, 2016, in connection with the acquisition of Empire, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, \$1.0 billion aggregate principal amount of 5.0% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering"). On March 9, 2016, the Underwriters exercised their option to purchase an additional \$150.0 million of Debentures, bringing the total amount of Debentures under the Debenture Offering to \$1.15 billion.

All Debentures were sold on an instalment basis at a price of \$1,000 dollars per Debenture, of which \$333 dollars was paid on the closing of the Offering (the "First Instalment") and the remaining \$667 dollars (the "Final Instalment") is payable on a date (the "Final Instalment Date") to be fixed by APUC following satisfaction of all conditions precedent to the closing of APUC's acquisition of Empire.

See also *Convertible Unsecured Subordinated Debentures in Liquidity and Capital Reserves*.

U.S. \$235 Million Term Credit Facility

On January 4, 2016, Algonquin entered into a U.S. \$235.0 million term credit facility with two U.S. banks. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2017.

Generation Group Highlights

Acquisition of 75% interest in the Red Lily I Partnership

Effective April 12, 2016, APUC, through its subsidiary, exercised its option to subscribe for a 75% equity interest in the Red Lily I Partnership, a 26.4 MW wind energy facility (the "Red Lily Wind Facility") located in southeastern Saskatchewan for which the Generation Group provides operation and supervision services. The equity interest was obtained in exchange for the outstanding amounts on two subordinated loans previously advanced by a subsidiary of the Company. Accordingly, effective the exercise date, the financial results of the Red Lily Wind Facility will be reported as part of consolidated operations of APUC.

Distribution Group Highlights

Acquisition of the Park Water System

On January 8, 2016, the Distribution Group closed a previously announced agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility Park Water Company, now known as Liberty Utilities (Park Water) Corp. (the "Park Water System"). The acquisition of the Park Water System was originally announced in September 2014. The 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 three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

Total consideration for the utility purchase was U.S. \$341.3 million, which includes the assumption of approximately U.S. \$91.5 million of existing debt. This acquisition maintains APUC's strategic business mix and further enhances its investment grade consolidated capital structure.

The water utility located in western Montana is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will

ultimately take possession of Mountain Water. See also: *Regulatory Risk - Condemnation Expropriation Proceedings* in the Annual MD&A.

2016 First Quarter Results From Operations

Key Selected Annual Financial Information

(all dollar amounts in \$ millions except per share information)	Three months ended March 31,	
	2016	2015
Revenue	\$ 341.7	\$ 381.9
Adjusted EBITDA ¹	147.9	114.5
Cash provided (used) by operating activities	53.4	(7.4)
Adjusted funds from operations ¹	121.8	101.0
Net earnings attributable to Shareholders	42.0	43.1
Adjusted net earnings ¹	56.1	42.6
Dividends declared to Common Shareholders	35.0	27.8
Weighted Average number of common shares outstanding	268,565,782	250,776,336
Per share		
Basic net earnings	\$ 0.15	\$ 0.16
Adjusted net earnings ^{1,2}	\$ 0.21	\$ 0.17
Diluted net earnings	\$ 0.14	\$ 0.16
Cash provided (used) by operating activities ^{1,2}	\$ 0.21	\$ (0.03)
Adjusted funds from operations ^{1,2}	\$ 0.46	\$ 0.41
Dividends declared to Common Shareholders	\$ 0.13	\$ 0.11
Total assets	5,615.5	4,531.4
Long term debt ³	2,214.5	1,482.7

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.

The Company's management's reporting structure is aligned under three business units: Generation, Distribution, and Transmission Business Groups. At present, the Transmission Business group is not material and is therefore grouped with Corporate.

For the three months ended March 31, 2016, APUC experienced an average U.S. exchange rate of approximately \$1.3741 as compared to \$1.2411 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 are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended March 31, 2016, APUC reported total revenue of \$341.7 million as compared to \$381.9 million during the same period in 2015, a decrease of \$40.2 million or 10.5%. The major factors resulting in the decrease in APUC revenue for the three months ended March 31, 2016 as compared to the corresponding period in 2015 are set out as follows:

(all dollar amounts in \$ millions)

Quarter ended
March 31, 2016

Comparative Prior Period Revenue	\$ 381.9
Existing Facilities: Generation	
Hydro: increase due to the recognition of Global Adjustment revenue from the Ontario Energy Financial Corporation ("OEFC") in Ontario and increased hydrology in the Maritime and Quebec regions caused by warmer temperatures and higher rainfall partly offset by lower retail load and revenues in the Maritime region.	3.4
Wind Canada: The St Leon Wind Facility experienced decreased wind resources.	(1.7)
Wind US: Increased wind resources at the Minonk and Senate Wind Facilities coupled with an increase in market pricing for the sale of Renewal Energy Credits.	2.0
Solar Canada: Increased solar resource at the Cornwall Solar Facility.	0.1
Thermal: The thermal facilities experienced a lower cost of gas (which are pass-through revenues).	(2.7)
Other	(0.3)
	0.8
New Facilities: Generation	
Wind Canada: The Morse Wind Facility achieved commercial operations in April 2015.	2.7
Solar US: The Bakersfield I Solar Facility achieved commercial operations in April 2015.	0.9
	3.6
Foreign Exchange	
Increased Generation Group revenues as a result of a stronger U.S. dollar.	4.2
Existing Facilities: Distribution	
Electric Distribution Systems: Decrease is primarily related to lower customer usage at the Granite State Electric System caused by warmer winter weather experienced in the region as compared to the prior year. The CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement at each month.	(10.1)
Natural Gas Distribution Systems: Decrease primarily due to warmer winter weather experienced at the natural gas systems resulting in lower heating degree days.	(69.2)
Water Distribution & Wastewater Treatment Systems: Increase primarily related to higher demand at the LPSCo and Bella Vista Water Systems.	0.7
Other: Decrease primarily due to fewer projects from contracted services.	(1.7)
	(80.3)
New Facilities: Distribution	
Water Distribution & Wastewater Treatment Systems: Revenues from the Park Water System which was acquired on January 8th, 2016.	15.4
	15.4
Rate Cases	
Natural Gas Distribution Systems: Implementation of new rates at the EnergyNorth, Peach State and the Illinois Natural Gas Systems.	3.1
Water Distribution & Wastewater Treatment Systems: Implementation of new rates at the Pine Bluff Water System.	0.1
	3.2
Foreign Exchange	
Increased Distribution Group revenues as a result of a stronger U.S. dollar.	12.9
Current Period Revenue	\$ 341.7

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

Adjusted EBITDA in the three months ended March 31, 2016 totalled \$147.9 million as compared to \$114.5 million during the same period in 2015, an increase of \$33.4 million or 29.2%.

For the three months ended March 31, 2016, net earnings attributable to Shareholders totalled \$42.0 million as compared to \$43.1 million during the same period in 2015, a decrease of \$1.1 million. The decrease was due to \$13.3 million in

increased depreciation and amortization expenses, \$1.0 million in increased administration charges, \$0.9 million in decreased foreign exchange gains, \$8.4 million in increased interest expense, \$6.0 million increased acquisition related costs, \$6.2 million increase in write-down of long lived assets, and \$1.0 million decrease in gains on derivative financial instruments. These items were partially offset by \$31.3 million in increased earnings from operating facilities, \$0.1 million increased dividend, equity and other income, \$0.9 million from decreased income tax expense (tax explanations are discussed in APUC: Corporate and Other Expenses) and \$3.5 million increased loss attributable to non-controlling interest, as compared to the same period in 2015.

During the three months ended March 31, 2016, cash provided by operating activities totalled \$53.4 million or \$0.21 per share as compared to cash used by operating activities of \$7.4 million, or \$0.03 per share during the same period in 2015. During the three months ended March 31, 2016, Adjusted funds from operations, a non-GAAP measure, totalled \$121.8 million or \$0.46 per share as compared to Adjusted funds from operations of \$101.0 million, or \$0.41 per share during the same period in 2015, an increase of \$20.8 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 represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2016 Adjusted EBITDA Summary

Adjusted EBITDA in the year ended March 31, 2016 totalled \$147.9 million as compared to \$114.5 million during the same period in 2015, an increase of \$33.4 million or 29.2%. The breakdown of Adjusted EBITDA (see *Non-GAAP Performance Measures*) by the company's main operating segments and summaries of changes are shown below.

Adjusted EBITDA by segment (all dollar amounts in \$ millions)	Three months ended March		
	2016	31, 2015	
Generation Business Group Operating Profit	\$ 63.4	\$ 45.7	
Distribution Business Group Operating Profit	95.3	78.6	
Administration Expenses	(11.4)	(10.4)	
Other Income & Expenses	0.6	0.6	
Total Algonquin Power & Utilities Adjusted EBITDA	\$ 147.9	\$ 114.5	
Change in Adjusted EBITDA (\$)	\$ 33.4		
Change in Adjusted EBITDA (%)	29.2%		

Change in Adjusted EBITDA Breakdown (all dollar amounts in \$ millions)	Three months ended March 31, 2016			
	Generation	Distribution	Corporate	Total
Prior period Balances	\$ 45.7	\$ 78.6	\$ (9.8)	\$ 114.5
Existing Facilities	8.8	(3.2)	—	5.6
New Facilities	3.5	6.0	—	9.5
Rate cases	—	3.2	—	3.2
Foreign Exchange Impact	5.4	10.7	—	16.1
Administration Expenses	—	—	(1.0)	(1.0)
Total change during the period	\$ 17.7	\$ 16.7	\$ (1.0)	\$ 33.4
Current Period Balances	\$ 63.4	\$ 95.3	\$ (10.8)	\$ 147.9

GENERATION BUSINESS GROUP

2016 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three months ended March 31	
		2016	2015
Hydro Facilities:			
Maritime Region	35.7	47.7	27.3
Quebec Region ¹	56.0	73.8	48.7
Ontario Region	36.0	40.3	37.8
Western Region	9.6	10.8	11.2
	137.3	172.6	125.0
Wind Facilities:			
St. Damase	20.9	22.5	20.5
St. Leon	121.4	91.0	123.9
Red Lily ²	23.2	18.5	22.4
Morse ³	30.5	21.9	—
Sandy Ridge	47.1	49.1	49.8
Minonk	200.6	209.4	176.7
Senate	151.3	153.4	109.3
Shady Oaks	109.7	97.6	100.0
	704.7	663.4	602.6
Solar Facilities:			
Cornwall	2.6	2.5	2.3
Bakersfield ⁵	9.1	7.9	—
	11.7	10.4	2.3
	853.7	846.4	729.9
Thermal Facilities:			
Windsor Locks	N/A ⁴	28.2	28.0
Sanger	N/A ⁴	32.0	31.9
		60.2	59.9
Total Performance	853.7	906.6	789.8

¹ The Generation Group's Donnacona Hydro Facility was offline during the second half of 2014 and throughout 2015 and 2016 to-date. Insurance proceeds were received to compensate for lost revenue. Reconstruction of the Donnacona Dam has commenced.

² Production from the Red Lily Wind Facility during the quarter is included as APUC manages the facility under contract. On April 12, 2016, APUC, through its subsidiary, exercised its option to acquire a 75% equity interest in the facility. Accordingly, effective the exercise date, the financial results of the Red Lily Wind Facility will now be reported as part of consolidated operations of APUC.

³ The Morse Wind Facility achieved commercial operation on April 22, 2015.

⁴ Natural gas fired co-generation facility.

⁵ The Bakersfield Solar Facility achieved commercial operation on April 14, 2015 in accordance with the provisions within the PPA.

2016 First Quarter Generation Performance

For the three months ended March 31, 2016, the Generation Group generated 906.6 GW-hrs of electricity as compared to 789.8 GW-hrs during the same period of 2015.

For the quarter, the hydro facilities generated 172.6 GW-hrs of electricity, as compared to 125.0 GW-hrs produced in the same period in 2015, an increase of 38.1%. Electricity generated represented 125.7% of long-term average resources ("LTAR") as compared to 91.0% during the same period in 2015. The increased generation is largely attributable to improved hydrology in the Maritimes and Quebec regions due to the warmer temperatures and higher rainfall.

For the three months ended March 31, 2016, the wind facilities produced 663.4 GW-hrs of electricity, as compared to 602.6 GW-hrs produced in the same period in 2015, an increase of 10.1%. The higher generation was a result of increased wind

resources at the Senate and Minonk Wind Facilities, in addition to the Morse Wind Facility achieving commercial operation in April 2015. During the three months ended March 31, 2016, the wind facilities (excluding the Morse Wind Facility) generated electricity equal to 95.3% of LTAR, as compared to 89.5% during the same period in 2015.

For the three months ended March 31, 2016, the solar facilities generated 10.4 GW-hrs of electricity, as compared to 2.3 GW-hrs of electricity in the same period in 2015, an increase of 352.2%. The increase in production is attributable to the new Bakersfield I Solar Facility which achieved commercial operation in accordance with the provisions of the PPA on April 14, 2015. Cornwall's production was 3.8% below its LTAR, as compared to 11.5% below its LTAR in the same period last year. Bakersfield I Solar Facility achieved 86.8% of its LTAR in the first quarter.

For the three months ended March 31, 2016, the thermal facilities generated 60.2 GW-hrs of electricity, as compared to 59.9 GW-hrs of electricity during the same period in 2015. During the same period, the Windsor Locks Thermal Facility generated 185.7 billion lbs of steam, as compared to 176.7 billion lbs of steam during the same period in 2015.

2016 Generation Group Operating Results

(all dollar amounts in \$ millions)	Three months ended March 31	
	2016	2015
Revenue ¹		
Hydro	19.7	16.0
Wind	35.7	30.2
Solar	2.4	1.1
Thermal	7.7	10.5
Total Revenue	\$ 65.5	\$ 57.8
Less:		
Cost of Sales - Energy ²	(1.1)	(6.2)
Cost of Sales - Thermal	(4.5)	(7.2)
Realized gain/(loss) on hedges ³	(1.0)	0.6
Net Energy Sales	\$ 58.9	\$ 45.0
Renewable Energy Credits ("REC") ⁴	6.1	4.9
Other Revenue	0.8	1.0
Total Net Revenue	\$ 65.8	\$ 50.9
Expenses & Other Income		
Operating expenses	(16.3)	(15.1)
Interest and Other income	0.5	1.0
HLBV income ⁵	13.4	8.9
Divisional operating profit	\$ 63.4	\$ 45.7

¹ While most of the Generation Group's PPAs include annual rate increases, a change to the weighted average production levels resulting in 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 ("RECs") 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 RECs 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 Hypothetical Liquidation at Book Value ("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.

2016 Three Month Operating Results

For the three months ended March 31, 2016, the Generation Group facilities generated \$63.4 million of operating profit as compared to \$45.7 million during the same period in 2015, which represents an increase of \$17.7 million or 38.7%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)	Quarter ended March 31, 2016
Prior Period Operating Profit	\$ 45.7
Existing Facilities	
Hydro Canada: (i) recognition of Global Adjustment revenue from OEFC in Ontario; (ii) increased hydrology in the Maritime and Quebec regions due to warmer temperatures and higher rainfall; and (iii) higher realized operating profit on sales to retail customers realized at the Maritime region caused by a lower market price for energy purchases and a greater proportion of energy requirements satisfied by the Tinker facility.	6.8
Wind Canada: The St Leon Wind Facility experienced decreased wind resources.	(1.6)
Wind US: Increased wind resources at the Minonk and Senate Wind Facilities coupled with an increase in market pricing for the sale of REC's. This was partly offset by lower wind resources and revenue at the Sandy Ridge Wind Facility. Lower production at the Shady Oaks Wind Facility was offset by Energy and Capacity rate increases.	5.0
Solar Canada: The Cornwall Solar Facility operated consistent with the prior year.	—
Thermal: The Sanger Thermal Facility incurred higher repairs and maintenance and property taxes as compared to the prior year.	(0.4)
Other	(1.0)
	8.8
New Facilities	
Wind Canada: The Morse Wind Facility achieved commercial operations in April 2015.	2.3
Solar US: The increase was due to operating and HLBV income associated with the Bakersfield I Solar Facility which achieved commercial operation in accordance with the provisions of the PPA in April 2015.	1.2
	3.5
Foreign Exchange	
Increased operating profit as a result of a stronger U.S. dollar.	5.4
Current Period Operating Profit	\$ 63.4

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)	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction						
Odell Wind Project ¹	Minnesota	200	\$419.2	2016	20	814.7
Bakersfield II Solar Project ²	California	10	35.1	2016	20	24.2
Deerfield Wind Project ³	Michigan	150	393.5	2016/17	20	555.2
Total Projects in Construction		360	\$847.8			1,394.1
Projects in Development						
Amherst Island Wind Project	Ontario	75	\$272.5	2017	20	235.0
Chaplin Wind Project	Saskatchewan	177	340.0	2017/18	25	720.0
Great Bay Solar Project ⁴	Maryland	75	233.8	2017	10	152.0
Val Eo Wind Project ⁵	Quebec	24	70.0	2017	20	66.0
Total Projects in Development		351	\$916.3			1,173.0
Total in Construction and Development		711	\$1,764.1			2,567.1

¹ Total cost of the project is expected to be approximately \$322.8 million in U.S. dollars.

² Total cost of the project is expected to be approximately \$27.0 million in U.S. dollars.

³ Total cost of the project is expected to be approximately \$303.0 million in U.S. dollars.

⁴ The total cost of the project is expected to be approximately \$180.0 million in U.S. dollars.

⁵ Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the Val-Eo Wind Project.

Projects in Construction

Odell Wind Project

The Odell Wind Project is a 200 MW wind powered electric generating development project located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota, and the project is being constructed on approximately 23,000 acres of leased land.

Construction of the project commenced in the second quarter of 2015. Turbine erection began in early November 2015, with 31 turbines installed to date. The collection system substation work was completed and successfully energized in cooperation with the Transmission Provider in December 2015, and the new 115kV transmission line has been built.

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 MW Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. During the quarter, the substation construction has been completed, interconnected and back-fed by the offtaker. The project has a commercial operations date targeted for the second quarter of 2016.

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 land leased from a supportive wind power land owner group.

Construction of the project commenced in the fourth quarter of 2015. Over 95% of the private land access roads have been constructed and public road improvements are underway. The main power transformer was shipped during the quarter. Turbine blade production is underway and engineering for the project is nearing completion. The project has a commercial operations date targeted for the fourth quarter of 2016.

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 has been made to the Environmental Review Tribunal ("ERT"). The appeal process is generally limited to a period of 6 months, although the ERT may grant extensions in certain cases. The hearing has now extended beyond six months and is expected to conclude in the second quarter of 2016. The project has a planned construction time frame of approximately 12 months once all approvals have been obtained.

Chaplin Wind Project

The Chaplin Wind Project is a 177 MW wind powered electric generating development project located in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2017 and 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; Phase II of the project, which comprises the remaining approximately 142 MW, will be the infill construction phase and will only proceed following evaluation of the wind resource at the site. Both phases require the completion of the necessary permitting.

In the first quarter of 2015, the Environmental Impact Statement documentation was submitted and meetings were held with the Ministry of Environment ("SKMOE"). Supplemental reports were submitted in the second and third quarters of 2015. The SKMOE completed the required 30 day public posting period on November 17, 2015. The SKMOE approval is expected to be issued in the second quarter of 2016. The turbine and balance of plant contractor selection will be finalized upon signing of the turbine supply agreement, which is in the final stages, and is dependent on the receipt of approval from SKMOE.

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 second 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 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; Phase II of the project would entail the development of an additional 101 MW and would be constructed following 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. After the permitting process was delayed at the provincial level, construction planned in 2015 has been re-evaluated due to the severe weather conditions in the region. The new schedule calls for Phase 1 construction to begin in 2016 with commissioning to occur in 2017. Total costs to complete the project are estimated at approximately \$70.0 million.

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 (all dollar amounts in U.S. \$ millions)	March 31, 2016		March 31, 2015	
	Assets	Total Connections	Assets	Total Connections
Electricity	\$ 346.0	93,000	\$ 327.8	93,000
Natural Gas	784.5	293,000	737.2	293,000
Water and Wastewater	498.1	178,000	260.8	103,000
Total	\$ 1,628.6	564,000	\$ 1,325.8	489,000
Accumulated Deferred Income Taxes	\$ 167.3		\$ 92.5	

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 quarter in connection with the closing of the acquisition of the Park Water System.

2016 Three Month Usage Results

Electric Distribution Systems

	Three months ended March 31	
	2016	2015
Average Active Electric Connections For The Period		
Residential	80,300	79,900
Commercial and Industrial	12,400	12,400
Total Average Active Electric Connections For The Period	92,700	92,300
Customer Usage (GW-hrs)		
Residential	165.8	166.7
Commercial and Industrial	219.5	221.3
Total Customer Usage (GW-hrs)	385.3	388.0

For the three months ended March 31, 2016 the electric distribution systems' usage totalled 385.3 GW-hrs, as compared to 388.0 GW-hrs for the same period in 2015, a decrease of 2.7 GW-hrs. Customer usage at the Granite State Electric system decreased by approximately 14.3 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 due to a colder winter in the region as compared to the prior year.

Natural Gas Distribution Systems

Three months ended
March 31

	2016	2015
Average Active Natural Gas Connections For The Period		
Residential	252,400	252,400
Commercial and Industrial	27,100	27,400
Total Average Active Natural Gas Connections For The Period	279,500	279,800
Customer Usage (MMBTU)		
Residential	7,870,000	10,056,000
Commercial and Industrial	4,837,000	6,113,000
Total Customer Usage (MMBTU)	12,707,000	16,169,000

For the three months ended March 31, 2016, usage at the natural gas distribution systems totalled 12,707,000 MMBTU, as compared to 16,169,000 MMBTU during the same period in 2015, a decrease of 3,462,000 MMBTU, or 21.4%. 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 in the EnergyNorth and Midstates Gas Systems service territories.

Water and Wastewater Distribution Systems

Three months ended
March 31

	2016	2015
Average Active Connections For The Period		
Wastewater connections	40,200	40,000
Water distribution connections	131,300	59,000
Total Average Active Connections For The Period	171,500	99,000
Gallons Provided		
Wastewater treated (millions of gallons)	598	577
Water sold (millions of gallons)	3,066	1,677
Total Gallons Provided	3,664	2,254

During the three months ended March 31, 2016, the water and wastewater distribution systems provided approximately 3,066 million gallons of water to its customers and treated approximately 598 million gallons of wastewater, as compared to 1,677 million gallons of water and 577 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.

2016 Three Month Operating Results

	Three months ended March 31,		Three months ended March 31,	
	2016 U.S. \$ (millions)	2015 U.S. \$ (millions)	2016 Can \$ (millions)	2015 Can \$ (millions)
Revenue				
Utility electricity sales and distribution	46.1	56.2	63.4	69.6
Less: Cost of Sales – Electricity	(28.4)	(37.4)	(39.2)	(46.3)
Net Utility Sales - Electricity	\$ 17.7	\$ 18.8	\$ 24.2	\$ 23.3
Utility natural gas sales and distribution	109.9	174.7	151.9	216.3
Less: Cost of Sales – Natural Gas	(46.7)	(111.5)	(64.7)	(138.0)
Net Utility Sales - Natural Gas	\$ 63.2	\$ 63.2	\$ 87.2	\$ 78.3
Utility water distribution & wastewater treatment sales and distribution	30.0	13.8	41.1	17.1
Less: Cost of Sales – Water	(2.0)	—	(2.8)	—
Net Utility Sales - Water Distribution & Wastewater Treatment	28.0	13.8	38.3	17.1
Gas Transportation	9.0	10.3	12.4	12.9
Other Revenue	0.4	1.9	0.6	2.3
Net Utility Sales	\$ 118.3	\$ 108.0	\$ 162.7	\$ 133.9
Operating expenses	(49.8)	(44.7)	(68.5)	(55.7)
Other income	1.0	0.7	1.1	0.4
Distribution Group operating profit	\$ 69.5	\$ 64.0	\$ 95.3	\$ 78.6

For the three months ended March 31, 2016, the Distribution Group reported an operating profit of U.S. \$69.5 million, as compared to U.S. \$64.0 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was \$95.3 million, as compared to \$78.6 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in \$ millions)

Prior Period Operating Profit	\$ 78.6
Existing Facilities	
Electric Distribution Systems: Decrease is primarily related to lower customer usage at the Granite State Electric System caused by warmer winter weather experienced in the region as compared to the prior year. The CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement at each month.	(1.0)
Natural Gas Distribution Systems: Decrease is primarily related to warmer winter weather experienced at the Energy North, Peach State, and Midstates Natural Gas Systems compared to the same period in the prior year.	(2.3)
Water Distribution & Wastewater Treatment Systems: Increase is primarily related to increased volumes at the LPSCo Water System.	0.8
Other Income: Decreased billings for contracted services as compared to the same period in 2015.	(0.7)
	(3.2)
New Facilities	
Water Distribution & Wastewater Treatment Systems: Acquisition of the Park Water System.	6.0
	6.0
Rate Cases	
Natural Gas Distribution Systems: Successful implementation of new rates at the EnergyNorth, Peach State, and the Illinois Natural Gas Systems.	3.1
Water Distribution & Wastewater Treatment Systems: Successful implementation of new rates at the Pine Bluff Water System.	0.1
	3.2
Foreign Exchange	
Increased operating profit as a result of a stronger U.S. dollar.	10.7
Current Period Operating Profit	\$ 95.3

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				
Peach State Gas System	Georgia	GRAM	\$3.4	Final Order issued in February 2016 approving a U.S. \$2.7 million rate increase effective March 1, 2016.
New England Gas System	Massachusetts	General Rate Case	\$11.8	Final Order issued in February 2016 approving a U.S. \$8.3 million rate increase, with U.S. \$7.8 million effective March 1, 2016 and U.S. \$0.5 million effective March 1, 2017.
Black Mountain Sewer System	Arizona	General Rate Case	\$0.4	Final Order issued in April 2016 approving U.S. \$0.2 million rate increase effective May 1, 2016.
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 and approval is expected in Q2 2016 allowing a revenue increase retroactive to Q1 2016.
Pending 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 is expected in Q4 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 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 is proposed for July 2016. A final permanent rate decision is expected in 2017.

Completed Rate Cases

On October 1, 2015, the Peach State Gas System filed an application for an increase in revenue of U.S. \$3.4 million in its annual GRAM filing with the Georgia Public Service Commission. The GRAM uses a 12 month base period ending June 2015 (historic test year), with adjustments for the 12 months ending September 2016 (forward looking test year). Commission approval was received in February 2016, allowing for a U.S. \$2.7 million rate increase effective March 1, 2016. The difference from the original proposed amount was due to tax depreciation rates and the use of revised inflationary factors applied to operating expenses.

On July 16, 2015, the New England Gas System filed an application with the Massachusetts Department of Public Utilities seeking an increase in revenue of U.S. \$11.8 million, or 14.6%, based on a test year ending December 31, 2014, adjusted for known and measurable changes. This application represents the first rate case under the Distribution Group's ownership and the first since 2009. The New England Gas System requests the increase in its general rates for increasing capital costs associated with maintaining the infrastructure and increases in operating and maintenance expenses. The increase reflects a requested return on equity of 10.4% and a debt/equity structure of 45%/55%. An all-party settlement was achieved and filed in December 2015. The settlement includes a two-step revenue increase totaling U.S. \$8.3 million, premised upon a 9.6% return on equity on 50% of capital. A U.S. \$7.8 million rate increase will occur on March 1, 2016 and a further U.S. \$0.5 million rate increase will occur on March 1, 2017, contingent upon certain employee additions. A decision approving the settlement was received in February 2016.

On June 22, 2015, the Black Mountain Wastewater System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. \$0.4 million, or 18.75%, based on a test year ending December 31, 2014. This rate case is primarily designed to resolve issues related to rate design and the closure of the treatment plant. No amounts have been removed from rate base in this application. The increase reflects a requested return on equity of 10.8% and a debt/equity structure of 30%/70%. An all-party settlement has been achieved and was filed on January 22, 2016. The settlement includes a revenue increase of U.S. \$0.2 million, premised upon a 9.5% return on equity on 70% of capital. A Recommended Opinion and Order was issued on March 25, 2016 supporting the settlement. A final commission decision was issued on April 22, 2016 approving the settlement and implementation of new rates as of May 1, 2016, much earlier than originally expected.

On May 1, 2015, the CalPeco Electric System filed an application with the California Public Utilities Commission ("CPUC") seeking an increase in revenue of U.S. \$13.6 million (of which U.S. \$11.4 million related to an increase in margin revenue, and 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 return on equity of 10.5% and a debt/equity structure of 45%/55%. The previous test year ended December 31, 2011. A comprehensive settlement was achieved in April and has been provided to the Administrative Law Judge. A final permanent rate decision is expected to approve the settlement in the second quarter of 2016. The new rates will be effective retroactively in the first quarter of 2016.

Pending Rate Cases and Other Applications of Note

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, 10.8% ROE, and 70% equity, for an overall rate of return of 8.6%. 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 is primarily needed to recover increased operating costs and capital improvements. It also includes 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 final decision and implementation of new rates is expected for the fourth quarter of 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 seeks 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, for an overall rate of return of 9.16%. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the FARE, a PPAM and a PTAM. A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending March 2009.

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, for an overall rate of return of 9.45%. Rates are proposed to be phased in over two years due to the magnitude of the increase. This rate case is primarily needed 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 case application. The application seeks a U.S. \$5.3 million annual increase proposed for effect July 1, 2016, which equates to a 15.0% increase to distribution revenue. Additionally, a U.S. \$2.4 million annual increase (step increase) is proposed to recover the revenue requirement associated with capital additions made in 2016. This combined increase would become effective at the time permanent rates become effective following the close of the proceeding, but no earlier than January 1, 2017. The total permanent and step increase being proposed is U.S. \$7.7 million annually, or a 21.8% increase to distribution revenue.

Other Applications

Related to the above CalPeco Electric System rate application are two additional applications in California. The first is an application filed with the CPUC on April 17, 2015 for the issuance of a Certificate of Public Convenience and Necessity ("CPCN") to acquire, own and operate a solar power generation station with a total generation capacity of up to 60MW (the "Solar Project"). The application requested authorization for rate recovery of the costs that the CalPeco Electric System will incur to acquire, own, and operate the Solar Project. The second is an application filed on April 24, 2015 with the CPUC requesting authority to enter into a new multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV Energy Services Agreement as energy purchase costs. This new PPA was required as an existing PPA with NV Energy expired at the end of 2015. The Distribution Group believes that these two applications allow the CalPeco Electric System to continue procurement of its energy supply in a cost-effective manner for its customers while also allowing the utility to meet its Renewables Portfolio Standard requirements. An Order approving the

Solar Application (revised to 50MW in a settlement) was issued in December 2015. An Order approving the new PPA was issued in January 2016.

On February 19, 2016, the Missouri Natural Gas System filed an Infrastructure System Replacement Surcharge (ISRS) application. The ISRS application allows utilities to file for a surcharge on customers' bills to reflect eligible capital additions since the update period in the last general rate case. The pending application includes U.S. \$2.2M of eligible capital additions from June 2015 through January 2016 worth an additional U.S. \$0.2M in annual revenues. Updated ISRS rates are expected to become effective in the second quarter of 2016.

On February 15, 2016, the Peach State Gas System submitted its annual Pipe Replacement Program (PRP) filing for the year ended September 30, 2015. The PRP filing seeks recovery of costs as it relates to the replacement of certain eligible cast iron and bare steel replacement. The proposed annual revenue requirement of U.S. \$7.6 million, a reduction of U.S. \$0.3 million from the previous year figure of U.S. \$7.9 million, is expected to become effective in third quarter of 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.

On January 29, 2016, the PSC initiated a proceeding to review the rates of Mountain Water Company to ensure they remain just and reasonable under the new ownership. A hearing took place on May 3-4, 2016 and a decision is expected in the second quarter of 2016.

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 District Electric Company and its subsidiaries. The Empire District Electric Company 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. Closing of the Transaction is subject to customary closing conditions, including the 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), and the Federal Energy Regulatory Commission (the FERC). The Transaction is expected to close in the first quarter of 2017. Applications to four commissions (OK, KS, MO, and AR) and FERC were filed on March 16, 2016. On May 6, 2016, the FERC issued an order approving the proposed acquisition of Empire District Electric. 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 District Electric by Liberty Utilities Co. The order approves the acquisition as filed, without any material conditions.

The Transaction is expected to close early in 2017.

TRANSMISSION BUSINESS GROUP

In 2014, APUC created the Transmission Group which the Company believes complements the growth of the Generation and Distribution Groups. The Transmission Group is responsible for identifying, evaluating, and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America.

Northeast Expansion Pipeline and Northeast Supply Pipeline

The Transmission Group had entered into an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. to undertake the development, construction and ownership of a natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "NEP Project") and to acquire equity investment rights in a new entity (the "NSP Project") to undertake the development, construction and ownership of a natural gas transmission pipeline from northeastern Pennsylvania to a point near Wright, New York.

Kinder Morgan announced its termination of the projects on April 20, 2016 due primarily to the lack of sufficient commercial commitments. The project is now going through a formal abandonment process with both its regulators, shippers and its owners.

The need to find solutions to natural gas constraints for commercial, industrial and residential customers in the Northeastern U.S. continues to exist. APUC's Transmission Group remains committed to finding and participating in solutions to ameliorate those constraints.

California intra-state transmission

The Transmission Group is upgrading the North Lake Tahoe Transmission System to enable eventual operation of the entire system at 120 kilovolts (KV). 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 will be to rebuild the 650 Line (10 miles) to 120kV which is scheduled for completion in 2016 for a total estimated cost of U.S. \$22.0 million; Phase II will be to 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 and Phase II is expected to be completed in 2017 for a total cost of approximately U.S. \$23.0 million; Phase III will be to rebuild the 625 Line from 60 kV to 120 kV (15 miles) at a total cost of approximately U.S. \$25.0 million. This phase will begin once the system demand approaches 100 MWs.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in \$ millions)	Three months ended March 31	
	2016	2015
Corporate and other expenses:		
Administrative expenses	\$ 11.4	\$ 10.4
(Gain)/Loss on foreign exchange	(0.3)	(1.2)
Interest expense on convertible debentures and bridge financing	5.9	—
Interest expense	19.2	16.6
Interest, dividend and other Income ¹	(1.0)	(1.0)
Write down of long lived assets and other (gains)/losses	5.0	(1.2)
Acquisition-related costs	6.3	0.3
(Gain)/Loss on derivative financial instruments	0.9	(0.1)
Income tax expense	18.5	19.4

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

2016 Three Month Corporate and Other Expenses

During the three months ended March 31, 2016, administrative expenses totalled \$11.4 million, as compared to \$10.4 million in the same period in 2015. The \$1.0 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth as well as a stronger U.S. dollar.

For the three months ended March 31, 2016, interest expense on convertible debentures and bridge financing totalled \$5.9 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 notes 7 and 10 of the financial statements for further disclosure.

For the three months ended March 31, 2016, interest expense totalled \$19.2 million, as compared to \$16.6 million in the same period in 2015. The increased interest expense 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 early 2016, and the assumed debt on the acquisition of the Park Water System. This was offset by repayments of the Shady Oaks Wind Facility senior debt, the LPSCO Water System IDA bond, and reduced draws on the company's credit facilities.

For the three months ended March 31, 2016, loss on derivative financial instruments totalled \$0.9 million, as compared to a gain of \$0.1 million in the same period in 2015. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

For the three months ended March 31, 2016, an income tax expense of \$18.5 million was recorded as compared to an income tax expense of \$19.4 million during the same period in 2015. The decrease is primarily due to decreased earnings from operations, offset by increased deferred taxes on HLBV income, and a stronger U.S. dollar.

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 audited 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.

(all dollar amounts in \$ millions)	Three months ended March 31	
	2016	2015
Net earnings attributable to shareholders	\$ 42.0	\$ 43.1
Add (deduct):		
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	1.7	0.6
Income tax expense	18.5	19.4
Interest expense	19.2	16.6
Interest expense on convertible debentures and bridge financing	5.9	—
Other gains	(1.2)	(1.2)
Write-down of long lived assets	6.2	—
Acquisition related costs	6.3	0.3
(Gain) / loss on derivative financial instruments	0.9	(0.1)
Realized gain / (loss) on energy derivative contracts	(1.0)	0.6
(Gain) / loss on foreign exchange	(0.3)	(1.2)
Depreciation and amortization	49.7	36.4
Adjusted EBITDA	\$ 147.9	\$ 114.5

Hypothetical Liquidation at Book Value (“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 months ended March 31, 2016 amounted to approximately \$13.4 million.

Reconciliation of Adjusted Net Earnings to net earnings

The following table is derived from and should be read in conjunction with the audited 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 March 31	
	2016	2015
Net earnings attributable to shareholders	\$ 42.0	\$ 43.1
Add (deduct):		
(Gain) / Loss on derivative financial instruments, net of tax	0.6	—
Realized gain / (loss) on derivative financial instruments, net of tax	(0.6)	0.1
Write-down of long lived assets	6.2	—
(Gain) / Loss on foreign exchange, net of tax	(0.2)	(0.8)
Interest expense on convertible debentures and bridge financing fees, net of tax	4.3	—
Acquisition costs, net of tax	3.8	0.2
Adjusted net earnings	\$ 56.1	\$ 42.6
Adjusted net earnings per share¹	\$ 0.21	\$ 0.17

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 March 31, 2016, Adjusted net earnings totalled \$56.1 million, as compared to Adjusted net earnings of \$42.6 million, an increase of \$13.5 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 audited Consolidated Statement of Operations and 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:

(all dollar amounts in \$ millions)	Three months ended March 31	
	2016	2015
Cash flows from operating activities	\$ 53.4	\$ (7.4)
Add (deduct):		
Changes in non-cash operating items	46.7	97.3
Production based cash contributions from non-controlling interests	9.5	10.8
Interest expense on convertible debentures and bridge financing fees	5.9	—
Acquisition costs	6.3	0.3
Adjusted funds from operations	\$ 121.8	\$ 101.0
Adjusted funds from operations per share¹	\$ 0.46	\$ 0.41

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 March 31, 2016, Adjusted funds from operations totalled \$121.8 million, as compared to Adjusted funds from operations of \$101.0 million, an increase of \$20.8 million as compared to the same period in 2015.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

(all dollar amounts in \$ millions)	Three months ended March 31	
	2016	2015
Generation Group	\$ 42.4	\$ 20.4
Distribution Group	36.1	23.5
Corporate	2.4	1.5
Total	\$ 80.9	\$ 45.4

2016 First Quarter Property Plant and Equipment Expenditures

During the three months ended March 31, 2016, the Generation Group incurred capital expenditures of \$42.4 million, as compared to \$20.4 million during the comparable 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, as compared to the prior year which included spend as it related to the completion of the Morse Wind and Bakersfield I Solar Facilities.

During the three months ended March 31, 2016, the Distribution Group invested \$36.1 million (U.S. \$27.3 million) in capital expenditures, as compared to \$23.5 million (U.S. \$18.7 million) during the comparable 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.

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 amounts drawn, letters of credit issued and outstanding amounts available to APUC and its operating groups as at March 31, 2016 under the Facilities:

	As at March 31, 2016				As at Dec 31 2015
(all dollar amounts in \$ millions)	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	\$ 65.0	\$ 439.0	\$ 259.7	\$ 763.7	\$ 783.3
Funds drawn on Facilities	—	(21.1)	—	(21.1)	(27.3)
Letters of Credit issued	(12.1)	(137.1)	(7.6)	(156.8)	(164.3)
Liquidity available under the Facilities	\$ 52.9	\$ 280.8	\$ 252.1	\$ 585.8	591.7
Cash on Hand				309.1	124.4
Total liquidity and capital reserves	\$ 52.9	\$ 280.8	\$ 252.1	\$ 894.9	\$ 716.1

As at March 31, 2016, the Company's \$65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had \$12.1 million of outstanding letters of credit. During the 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.

As at March 31, 2016, the Generation Group's facilities consisted of \$350.0 million Generation Credit Facility and \$89.0 million Generation LC Facility (Cdn. \$50 million and U.S. \$30 million). As at March 31, 2016, the group had drawn \$21.1 million and had \$137.1 million in outstanding letters of credit. The facilities mature on July 31, 2019 and October 30, 2016, respectively.

As at March 31, 2016, the Distribution Group's \$259.7 million (U.S. \$200.0 million) senior unsecured revolving credit facility was undrawn and had \$7.6 million (U.S. \$5.9 million) of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants.

Long Term Debt

On January, 4, 2016, the Company entered into a U.S. \$235.0 million term credit facility with two U.S. banks. The term credit facility provides increased liquidity and is available for acquisitions and general corporate purposes and matures on July 5, 2017.

On January 8, 2016, the Company assumed U.S. \$91.5 million 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. \$4.0 million of debt outstanding under its revolving credit facilities. The remaining U.S. \$87.5 million of debt is secured by a first mortgage indenture and consists of a U.S. \$22.5 million 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 4.5% to 8.8%.

Convertible Unsecured Subordinated Debentures

On February 9, 2016, in connection with the acquisition of Empire, the Company completed the sale of \$1.0 billion aggregate principal amount of 5.0% convertible unsecured subordinated debentures. The Debentures trade on the TSX under the ticker symbol "AQN.IR". The Debentures were sold on an installment basis at a price of \$1,000 dollars per Debenture, of which \$333 dollars was paid on closing of the Debenture Offering and the remaining \$667 dollars (the "Final Installment") is payable on a date ("Final Installment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire. On March 9, 2016, the Underwriters exercised their option to acquire an additional \$150.0 million of Debentures, bringing the total Debentures issued under the Instalment Debenture Offering to \$1.15 billion.

The Debentures will mature on March 31, 2026 and bear interest at an annual rate of 5% per \$1,000 dollars principal amount of Debentures until and including the Final Installment Date, after which the interest rate will be 0%. Based on the first installment of \$333 dollars per \$1,000 dollars principal amount of Debentures, the effective annual yield to and including the Final Installment Date is 15%, and the effective annual yield thereafter is 0%.

If the Final Installment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of Debentures who have paid the final installment on or before the Final Installment Date will be entitled to receive, on the business day following the Final Installment Date, in addition to the payment of accrued and unpaid interest to and including the Final Installment Date, an amount equal to the interest that would have accrued from the day following the Final Installment Date to and including the first anniversary of the closing of the Debenture Offering had the 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 Installment Date occurs on or after the first anniversary of the closing of the Debenture Offering. Prior to the closing of the Acquisition, the Company will at all times have cash on hand or maintain readily available

capacity under the revolving credit facilities of not less than the aggregate amount of the first installment paid on the closing of the Debenture Offering and the exercise of the over-allotment option.

At the option of the holders and provided that payment of the Final Installment has been made, each Debenture will be convertible into common shares of the Company at any time after the Final Installment 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 Installment Date, the Debentures may not be redeemed by the Company, except that 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 Installment 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 dollars plus accrued and unpaid interest to the holder of the installment receipt. In addition, after the Final Installment Date, any 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 Installment 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.

Bridge Facility

On February 9, 2016, in connection with the acquisition of Empire, the Company obtained U.S. \$1.6 billion in bridge financing commitments from a syndicate of banks. The non-revolving term credit facilities are comprised of a U.S. \$1.065 billion debt bridge facility and a U.S. \$535.0 million equity bridge facility, both repayable in full on the first anniversaries following their advance. Upon issuing the Debentures (note 10) and receiving the First Instalment, the Company reduced the bridge commitments by U.S. \$263.6 million, as such a total commitment of U.S. \$1,336.4 million remains available to the company.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poors ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). APCo has a BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing entity of Liberty Utilities Co, has a BBB (high) issuer rating from DBRS.

On February 9, 2016, S&P revised its ratings outlook on APUC and its subsidiaries to negative from stable, while affirming the existing ratings for each of such companies, including the 'BBB' long-term corporate rating on APUC. S&P indicated that the negative outlook reflects the execution risk associated with the Empire Acquisition and the potential for lower ratings stemming from the limited ability to absorb weaker financial performance. The revised outlook also reflects S&P's expectation that certain of the Company's consolidated pro forma credit metrics will materially weaken due to the Debenture Offering (S&P treats the Debentures represented by Instalment Receipts as debt until they are converted into Common Shares).

On February 10, 2016, DBRS Limited ("DBRS") placed APCo's and APUC's 'BBB (low)' Issuer Ratings and APUC's 'Pfd-3 (low)' Preferred Shares ratings 'Under Review with Developing Implications'. DBRS also placed the 'BBB (high)' Issuer Rating, 'BBB (high)' Series A, Series C, and Series D Senior Notes ratings of Liberty Utilities Finance GP1, a special purpose financing entity of Liberty Utilities and the 'BBB (low)' Senior Unsecured Debentures ratings of APCo 'Under Review with Developing Implications'. The ratings actions reflect DBRS's view that the Acquisition will have a relatively neutral impact on the business risk assessments of APUC and its subsidiaries, and that the impact on the financial risk assessment was at the time of the ratings actions uncertain since the financing plan had not been finalized. For APCo, the DBRS announcement states that the credit quality of APCo could be indirectly affected should APUC's credit profile significantly deteriorate following the Acquisition. This reflects DBRS's view that APCo relies partly on APUC to provide equity injections to maintain key financial metrics within the rating category and that if APUC's debt levels increase significantly following the Acquisition, the Company may require more dividends from APCo to service its debt. DBRS indicated that it will review the finalized financing plan and further review any potential impact of the Acquisition on each entity's credit profile.

Contractual Obligations

Information concerning contractual obligations as of March 31, 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	\$ 1,845.5	\$ 9.9	\$ 525.6	\$ 203.6	\$ 1,106.4
Convertible Debentures	358.0	—	—	—	358.0
Advances in aid of construction	127.8	3.5			124.3
Interest on long-term debt obligations	909.9	146.1	145.3	121.2	497.3
Purchase obligations	171.6	171.6			
Environmental obligations	73.3	5.1	34.3	5.5	28.4
Derivative financial instruments:					
Cross currency swap	79.9	3.6	6.7	41.6	28.0
Interest rate swap	16.9	—	16.9	—	—
currency forward	0.2	0.2	—	—	—
Energy derivative contracts	0.4	0.4	—	—	—
Purchased power	259.0	60.5	102.9	95.6	—
Gas delivery, service and supply agreements	275.0	61.9	81.1	58.9	73.1
Long term service agreements	651.8	36.2	67.9	67.9	479.8
Capital projects	220.7	190.3	30.0	0.4	—
Operating leases	135.8	5.8	11.0	10.2	108.8
Other obligations	69.9	12.5	—	—	57.4
Total obligations	\$ 5,195.7	\$ 707.6	\$ 1,021.7	\$ 604.9	\$ 2,861.5

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 March 31, 2016, APUC had 258,912,456 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.

On February 9, 2016, the Company completed the sale of \$1.0 billion aggregate principal amount of 5.0% convertible unsecured subordinated debentures (the "Debentures"). On March 9, 2016 the Underwriters exercised the option to purchase an additional \$150.0 million of Debentures bringing the total Debentures sold by APUC to \$1.15 billion.

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.

On December 2, 2015, APUC completed the offering of 14,355,000 common shares at a price of \$10.45 per share, for gross proceeds of approximately \$150.0 million.

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 March 31, 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 March 31, 2016, 55.8 million common shares representing approximately 22% of total shares outstanding had been registered with the Reinvestment Plan. During the quarter ended March 31, 2016, 292,337 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on April 15, 2016, an additional 705,735 common shares were issued under the Reinvestment Plan.

Emera shareholdings and subscription receipts

On October 7, 2014, the Company issued 8,708,170 Subscription Receipts of APUC at a purchase price of \$8.90 per Subscription Receipt for an aggregate subscription price of \$77.5 million. The investment was made under the Strategic Investment Agreement between Emera Inc. (“Emera”) and APUC, in support of the acquisition by APUC of the Odell Wind Project in Minnesota (the “Odell Acquisition”). As at November 14, 2015 (the first anniversary of the closing of the Odell Acquisition), the Subscription Receipts were convertible to common shares of APUC on a one-for-one basis, subject to adjustments as provided in the applicable subscription agreement. On October 7, 2016, the Subscription Receipts will automatically convert into common shares of APUC, if Emera has not yet exercised its option to convert.

On December 29, 2014, the Corporation issued 3,316,583 subscription receipts of APUC at a purchase price of \$9.95 per subscription receipt for an aggregate subscription price of \$33.0 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Park Water System in Montana and California (the “Park Water Acquisition”). The proceeds of the subscription have been used by APUC to partially finance the Park Water Acquisition. As at December 29, 2015 (the first anniversary of the closing of the subscription transaction), the Subscription Receipts were convertible to common shares of APUC on a one-for-one basis, subject to adjustments as provided in the applicable subscription agreement. On December 29, 2016, the Subscription Receipts will automatically convert into common shares of APUC, if Emera has not yet exercised its option to convert.

Conversion of the aforementioned Subscription Receipts into common shares is conditional on Emera’s holdings not exceeding 25% of the outstanding common shares of APUC at the time of conversion.

As at May 12, 2016, in total, Emera owns 50,126,766 APUC common shares representing approximately 19.3% of the total outstanding common shares of the Company, and there are 12,024,753 subscription receipts currently held by Emera. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE BASED COMPENSATION PLANS

For the three months ended March 31, 2016, APUC recorded \$1.0 million in total share-based compensation expense, as compared to \$0.9 million for the same period in 2015. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the audited Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at March 31, 2016, total unrecognized compensation costs related to non-vested options and share unit awards were \$8.9 million and \$1.5 million, respectively, and are expected to be recognized over a period of 2.36 and 1.42 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 quarter, the Company granted 2,487,601 options to executives of the Company. The options allow for the purchase of common shares at a price of \$10.82, 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 March 31, 2016, a total of 5,936,590 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. The PSUs provide for settlement in cash or shares at the election of APUC. As a result,

the PSUs are accounted as equity awards. During the quarter, the Company granted (including dividends) 6,453 PSUs to executives and employees of the Company.

As at March 31, 2016, a total of 570,569 PSU's are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards. During the quarter, the Company issued 16,691 DSUs to the directors of the Company.

As at March 31, 2016, a total of 174,162 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 quarter, the Company issued 29,720 common shares to employees under the ESPP plan.

As at March 31, 2016, a total of 381,486 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 months ended March 31, 2016, the Energy Services Business sold electricity to Maine Public Service Company ("MPS") and Bangor Hydro ("BH"), both of which are subsidiaries of Emera, amounting to U.S. \$2.6 million (2015 - U.S. \$1.6 million). For the three months ended March 31, 2016, Liberty Utilities purchased natural gas amounting to U.S. \$1.9 million (2015 - U.S. \$0.1 million) 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.

There was U.S. \$0.3 million included in accruals for the three months ended March 31, 2016 (December 31, 2015 - U.S. \$0.3 million) related to these transactions.

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees \$0.7 million (2015 - \$0.4 million) during the three months ended March 31, 2016.

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 prices 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 prices would result in a change in revenue of approximately U.S. \$1.9 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. \$1.9 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 March 31, 2016, the Generation Group had not entered into any such hedges.

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 March 31, 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 \$21.1 million outstanding as at March 31, 2016. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.2 million annually.
- The Distribution Credit Facility is subject to a variable interest rate and had no amounts outstanding as at March 31, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The Corporate Term Facility is subject to a variable interest rate and had \$305.0 million (U.S. \$235.0 million) outstanding as at March 31, 2016. As a result, 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 \$29.2 million (U.S. \$22.5 million) outstanding as at March 31, 2016. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.3 million annually

- 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 into 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 March 31, 2016, APUC and its subsidiaries had a combined \$585.8 million of liquidity available under the Facilities remaining and \$309.1 million of cash on hand resulting in \$894.9 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 totals approximately \$2,214.5 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 project 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 legal proceedings and appeals in connection with this matter. Both the Algonquin entities and Trafalgar had certain motions before the Bankruptcy Court seeking determinations on a number of matters. On November 13, 2015, the Bankruptcy Court entered judgment that: (1) grants Algonquin's motion for summary judgment; (2) denies Trafalgar's motion for summary judgment; and (3) dismisses Trafalgar's Adversary Complaint on the merits. Trafalgar has appealed the Judgment. Trafalgar has brought a motion for reconsideration of this judgment.

Additionally, Trafalgar has alleged in various pleadings before the Bankruptcy Court that the Algonquin entities have mismanaged the operations of the Trafalgar Hydro Facilities (now sold as noted below) under the Management Agreement dated January 15, 1996. No demand has been made based on these allegations. Any such claims are subject to an arbitration clause under

the Management Agreement. Algonquin denies any liability under either the 1995 agreement or the Management Agreement and will continue to vigorously defend against these claims.

The Bankruptcy Court approved the sale of all seven of the Trafalgar Hydro Facilities, all of which have now been closed. The parties returned to mediation on April 6, 2016 and reached a settlement which has been read into the Court record and approved by the Bankruptcy Court subject to notice to all parties in interest with an opportunity to object, which objection deadline was May 3, 2016. On May 3, 2016 US Bank objected to the Order approving the settlement. It is anticipated that the objection will be heard by the Bankruptcy Court Judge sometime in May or June, 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. The OEFC may seek leave to appeal to the Supreme Court of Canada by June 20, 2016.

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 \$6.8 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 interests on any amount ultimately determined to be payable or recoverable.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended March 31, 2016:

(all dollar amounts in \$ millions except per share information)	2nd Quarter 2015	3rd Quarter 2015	4th Quarter 2015	1st Quarter 2016
Revenue	\$ 196.2	\$ 189.6	\$ 260.3	\$ 341.7
Adjusted EBITDA	81.1	70.2	109.6	147.9
Net earnings / (loss) attributable to shareholders from continuing operations	20.6	16.7	38.1	42.0
Net earnings / (loss) attributable to shareholders	19.9	16.5	38.0	42.0
Net earnings / (loss) per share from continuing operations	0.07	0.06	0.14	0.15
Net earnings / (loss) per share	0.07	0.05	0.14	0.15
Adjusted net earnings	22.2	17.3	39.7	56.1
Adjust net earnings per share	0.08	0.06	0.15	0.21
Total Assets	4,396.5	4,759.0	4,991.7	5,615.5
Long term debt ¹	1,440.3	1,613.3	1,486.8	2,214.5
Dividend declared per common share	0.12	0.13	0.13	0.13
	2nd Quarter 2014	3rd Quarter 2014	4th Quarter 2014	1st Quarter 2015
Revenue	\$ 188.6	\$ 151.6	\$ 259.3	\$ 381.9
Adjusted EBITDA	66.4	41.4	84.3	114.5
Net earnings / (loss) attributable to shareholders from continuing operations	15.3	(6.1)	33.1	43.1
Net earnings/(loss) attributable to shareholders	14.6	(6.3)	31.6	43.1
Net earnings / (loss) per share from continuing operations	0.06	(0.04)	0.13	0.16
Net earnings/(loss) per share	0.06	(0.04)	0.13	0.16
Adjusted net earnings	16.6	(0.4)	35.2	42.6
Adjust net earnings per share	0.07	(0.01)	0.14	0.17
Total Assets	3,553.6	3,799.3	4,105.1	4,531.4
Long term debt ¹	1,381.0	1,404.3	1,271.7	1,482.7
Dividend declared per common share	0.09	0.10	0.10	0.11

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 \$151.6 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 loss of \$6.3 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 March 31, 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 March 31, 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 control 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 three months ended March 31, 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 three months period ended March 31, 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)

	March 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 309,118	\$ 124,353
Accounts receivable, net (note 4)	182,257	186,681
Natural gas in storage	11,881	28,502
Regulatory assets (note 5)	40,783	32,213
Prepaid expenses	27,722	18,409
Derivative instruments (note 21)	19,138	15,039
Other current assets	23,264	18,537
	614,163	423,734
Property, plant and equipment, net	4,007,404	3,873,684
Intangible assets, net	73,352	77,963
Goodwill	299,571	110,493
Regulatory assets (note 5)	235,171	213,102
Derivative instruments (note 21)	75,124	73,322
Long-term investments (note 6)	259,612	174,802
Deferred income taxes	20,506	18,109
Other assets	30,551	26,516
	\$ 5,615,454	\$ 4,991,725

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 23,926	\$ 50,428
Accrued liabilities	147,671	193,320
Dividends payable (note 13)	41,109	41,802
Regulatory liabilities (note 5)	47,150	44,167
Long-term debt (note 7)	9,856	8,945
Other long-term liabilities and deferred credits (note 9)	36,470	36,621
Other liabilities	11,343	16,593
	317,525	391,876
Long-term debt (note 7)	1,846,738	1,477,850
Convertible debentures (note 10)	357,950	—
Regulatory liabilities (note 5)	126,255	131,180
Deferred income taxes	238,899	175,799
Derivative instruments (note 21)	93,248	106,628
Pension and other post-employment benefits (note 8)	159,270	150,094
Other long-term liabilities (note 9)	265,505	223,135
Preferred shares, Series C	17,539	17,548
	3,105,404	2,282,234
Redeemable non-controlling interest	22,654	25,751
Equity:		
Preferred shares	213,805	213,805
Common shares (note 11(a))	1,828,611	1,808,894
Subscription receipts	110,503	110,503
Additional paid-in capital	35,379	38,241
Deficit	(522,477)	(523,116)
Accumulated other comprehensive income (note 12)	172,122	286,737
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,837,943	1,935,064
Non-controlling interests	331,928	356,800
Total Equity	2,169,871	2,291,864
Commitments and contingencies (note 19)		
Subsequent events (note 6(e))		
	\$ 5,615,454	\$ 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 March 31

	2016	2015
Revenue		
Regulated electricity distribution	\$ 63,396	\$ 69,589
Regulated gas distribution	164,279	229,212
Regulated water reclamation and distribution	41,173	17,079
Non-regulated energy sales	65,502	57,712
Other revenue	7,395	8,262
	341,745	381,854
Expenses		
Operating expenses	85,102	71,160
Regulated electricity purchased	39,178	46,259
Regulated gas purchased	64,784	138,032
Regulated water purchased	2,757	—
Non-regulated energy purchased	5,615	13,423
Administrative expenses	11,418	10,447
Depreciation and amortization	49,725	36,387
Gain on foreign exchange	(302)	(1,243)
	258,277	314,465
Operating income from continuing operations	83,468	67,389
Interest expense on convertible debentures and bridge financing (notes 7 and 10)	5,863	—
Interest expense on long-term debt and others	19,200	16,633
Interest, dividend, equity and other income	(2,596)	(2,455)
Other gains	(1,216)	(1,203)
Acquisition-related costs	6,294	299
Write-down of long-lived assets (note 6(c))	6,185	—
Loss (gain) on derivative financial instruments (note 21(b)(iv))	942	(97)
	34,672	13,177
Earnings from continuing operations before income taxes	48,796	54,212
Income tax expense (note 16)		
Current	2,558	1,636
Deferred	15,946	17,755
	18,504	19,391
Net earnings	30,292	34,821
Net loss attributable to non-controlling interests (note 15)	(11,744)	(8,285)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 42,036	\$ 43,106
Series A and D Preferred shares dividend (note 13)	2,600	2,600
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	\$ 39,436	\$ 40,506
Basic net earnings per share (note 17)	\$ 0.15	\$ 0.16
Diluted net earnings per share (note 17)	0.14	0.16

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 March 31

	2016	2015
Net earnings	\$ 30,292	\$ 34,821
Other comprehensive (loss) income:		
Foreign currency translation adjustment, net of tax recovery of \$Nil and \$Nil, respectively (note 21(b)(iii))	(158,547)	141,192
Change in fair value of cash flow hedges', net of tax expense of \$1,486 and \$5,095, respectively (note 21(b)(ii))	21,566	6,444
Change in fair value of available-for-sale investments	25	(47)
Change in pension and other post-employment benefits, net of tax expense of \$92 and tax recovery of \$256, respectively (note 8)	68	(54)
Other comprehensive (loss) income, net of tax	(136,888)	147,535
Comprehensive (loss) income	(106,596)	182,356
Comprehensive (loss) income attributable to the non-controlling interests	(34,017)	20,823
Comprehensive (loss) income attributable to shareholders of Algonquin Power & Utilities Corp.	\$ (72,579)	\$ 161,533

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 Three months ended March 31, 2016

	Algonquin Power & Utilities Corp. Shareholders						Non-controlling interests	Total
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI		
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)					42,036		(11,744)	30,292
Redeemable non-controlling interests not included in equity							1,388	1,388
Other comprehensive loss						(114,615)	(22,273)	(136,888)
Dividends declared and distributions to non-controlling interests					(34,514)		(1,697)	(36,211)
Dividends and issuance of shares under dividend reinvestment plan	3,046				(3,046)			—
Contributions received from non-controlling interests							9,454	9,454
Shares issued pursuant to public offering, net of costs	(22)							(22)
Issuance of common shares under employee share purchase	290							290
Share-based compensation				1,073				1,073
Issuance of common shares under stock option exercise, net of withholding taxes	16,403			(3,935)	(3,837)			8,631
Balance, March 31, 2016	\$1,828,611	\$213,805	\$ 110,503	\$ 35,379	\$ (522,477)	\$ 172,122	\$331,928	\$2,169,871

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 March 31	
	2016	2015
Cash provided by (used in):		
Operating Activities		
Net earnings	\$ 30,292	\$ 34,821
Adjustments and items not affecting cash:		
Depreciation and amortization	51,841	35,871
Deferred taxes	15,946	17,755
Unrealized loss (gain) on derivative financial instruments	(5,278)	96
Share-based compensation expense	1,073	892
Cost of equity funds used for construction purposes	(497)	(550)
Pension and post-employment expense	2,158	1,108
Write-down of long-lived assets	6,185	366
Unrealized gain on disposal of VIE	—	220
Increase in deferred income	(1,590)	(744)
Changes in non-cash operating items (note 20)	(46,699)	(97,262)
	53,431	(7,427)
Financing Activities		
Cash dividends on common shares	(32,607)	(17,432)
Cash dividends on preferred shares	(2,600)	(2,600)
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	(1,842)	(613)
Issuance of common shares, net of costs	269	(46)
Issuance of convertible debentures, net of costs	357,950	—
Proceeds from exercise of share options	19,493	—
Shares surrendered to fund withholding taxes on exercised share options	(5,218)	—
Increase in long-term debt	352,295	137,330
Decrease in long-term debt	(24,444)	(609)
Increase in other long-term liabilities	3,834	2,208
Decrease in other long-term liabilities	(2,265)	(1,662)
	674,319	127,413
Investing Activities		
Increase (decrease) in other assets	(6,679)	242
Distributions received in excess of equity income	(2,766)	(21)
Receipt of principal on notes receivable	11,690	2,530
Additions to property, plant and equipment	(80,905)	(45,401)
Acquisitions of long-term investments	(114,212)	(61,324)
Acquisitions of operating entities	(333,084)	(3,388)
	(525,956)	(107,362)
Effect of exchange rate differences on cash	(17,029)	746
Increase (decrease) in cash and cash equivalents	184,765	13,370
Cash and cash equivalents, beginning of the period	124,353	9,273
Cash and cash equivalents, end of the period	\$ 309,118	\$ 22,643
Supplemental disclosure of cash flow information:	2016	2015
Cash paid during the year for interest expense	\$ 28,857	\$ 25,647
Cash paid during the year for income taxes	\$ 6,908	\$ 464
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	\$ 16,507	\$ 18,262
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	\$ 3,336	\$ 6,931

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

(in thousands of Canadian dollars, except as noted and per share amounts)

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”).

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.

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 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 unaudited interim consolidated financial statements.

2. Recently issued accounting pronouncements (continued)

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

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 unaudited interim 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 unaudited interim 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 and the International Accounting Standards Board have jointly issued a new revenue recognition standard codified in U.S. GAAP as ASU 2014-09, Revenue from Contracts with Customers (Topic 606). 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. During the quarter, the FASB approved a one year deferral of the effective date of this new revenue standard and as such, it is now 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 assessing the impact the adoption of this standard might have on its financial position or results of operations.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

(in thousands of Canadian dollars, except as noted and per share amounts)

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 \$3,400,000 (U.S.\$2,400,000), which includes the assumption of approximately \$1,300,000 (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 approval of Empire's common shareholders, and the receipt of certain state and federal regulatory and government approvals.

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).

(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.\$249,812, net of the debt assumed of U.S.\$91,450 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	\$ 1,957
Property, plant and equipment	345,254
Notes receivable	1,482
Goodwill	213,415
Regulatory assets	56,627
Long-term debt	(146,302)
Regulatory liabilities	(3,802)
Pension and OPEB	(17,318)
Deferred income tax liability, net	(58,008)
Other liabilities	(39,846)
Total net assets acquired	\$ 353,459

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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)**(b) Acquisition of Park Water System (continued)**

Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water Company. The City's right to take Mountain Water Company is currently on appeal before the Montana Supreme Court. If the City of Missoula prevails on appeal and ultimately takes possession of Mountain Water Company, the compensation to be paid by the City of Missoula for such taking will be the value of the utility plus accrued interest and attorney's fees as determined by the Montana court.

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 \$21,141 and net earnings of \$3,735 to the Company's unaudited interim consolidated financial results for the three months ended March 31, 2016.

4. Accounts receivable

Accounts receivable as of March 31, 2016 include unbilled revenue of \$37,519 (December 31, 2015 - \$49,002) from the Company's regulated utilities. Accounts receivable as of March 31, 2016 are presented net of allowance for doubtful accounts of \$9,478 (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.

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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***5. Regulatory matters (continued)**

Regulatory assets and liabilities consist of the following:

	March 31, 2016	December 31, 2015
Regulatory assets		
Environmental remediation	\$ 104,770	\$ 116,747
Pension and post-employment benefits	75,317	69,537
Commodity costs adjustment	10,038	7,643
Rate case costs	7,007	6,535
Rate adjustment mechanism	24,948	14,804
Debt premium	25,033	5,132
Other	28,841	24,917
Total regulatory assets	\$ 275,954	\$ 245,315
Less current regulatory assets	(40,783)	(32,213)
Non-current regulatory assets	\$ 235,171	\$ 213,102
Regulatory liabilities		
Cost of removal	\$ 102,911	\$ 107,988
Rate-base offset	22,648	24,984
Commodity costs adjustment	33,590	32,423
Other	14,256	9,952
Total regulatory liabilities	\$ 173,405	\$ 175,347
Less current regulatory liabilities	(47,150)	(44,167)
Non-current regulatory liabilities	\$ 126,255	\$ 131,180

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***6. Long-term investments**

Long-term investments consist of the following:

	March 31, 2016	December 31, 2015
Equity-method investees		
50% interest in Odell Wind Project Joint Venture (a)	\$ 41,003	\$ 42,287
50% interest in Deerfield Wind Project Joint Venture (b)	3,250	2,240
Interests in natural gas pipeline developments (c)	—	5,623
Other	2,820	2,323
	\$ 47,073	\$ 52,473
 Available-for-sale investment	 \$ 3,542	 \$ 2,946
 Notes receivable		
Development loans (d)	\$ 181,405	\$ 96,924
Red Lily Senior loan Tranche 2, interest at 6.31% (e)	—	11,588
Red Lily Subordinated loan Tranche 1 and Tranche 2, interest at 12.5% (e)	22,153	6,565
Other	5,439	4,306
	208,997	119,383
Total long-term investments	\$ 259,612	\$ 174,802

(a) Odell Wind Project Joint Venture

The Company owns 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 Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments, within 30 days of commencement of operations, which is expected in 2016. The total construction costs of the Odell Wind Project are estimated to be U.S.\$322,766. The interest capitalized during the three months period ended March 31, 2016 to the investment while the Odell Wind Project is under construction amounts to \$1,399 (2015 - nil).

(b) Deerfield Wind Project Joint Venture

On October 15, 2015, the Company acquired a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 150 MW construction-stage wind development project ("Deerfield Wind Project") in the state of Michigan. The total construction costs of the Deerfield Wind Project are estimated to be U.S.\$303,000.

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. Upon execution of third-party construction loan and tax equity documents expected in 2016, each party will contribute another U.S.\$18,596 plus accrued interest at 7% 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. The interest capitalized during the three months period ended March 31, 2016 to the investment while the Deerfield Wind Project is under construction amounts to \$1,189 (2015 - nil).

(c) Natural gas pipeline developments

APUC wrote off an amount of \$6,185 representing the total value of its equity interest in the natural gas development projects as at March 31, 2016, as both projects have been canceled by the developer.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***6. Long-term investments (continued)****(d) Development loans**

In the first quarter of 2016, the Company advanced U.S. \$69,650 to the Odell and Deerfield Wind Projects for total advances of U.S. \$139,682 as at March 31, 2016

The following credit support was issued by the Company in the first quarter of 2016: US. \$281

(e) Red Lily I

The Red Lily I Partnership (the "Partnership") is owned by an independent investor. APUC provides 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.

Subsequent to quarter-end, 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.

7. Long-term debt

Long-term debt consists of the following:

	March 31, 2016	December 31, 2015
Corporate		
U.S.\$235,000 Term Facility	305,031	—
Generation Group		
\$350,000 Revolving Credit Facility	21,100	27,300
\$485,000 Algonquin Power Co. - Senior Unsecured Notes	482,146	481,991
\$34,440 Long Sault Hydro Facility - Senior debt	34,440	34,760
\$2,470 Chuteford Hydro Facility - Senior debt	2,470	2,587
Distribution Group		
U.S.\$525,000 Liberty Utilities Co. - Senior unsecured notes	677,229	721,581
U.S.\$ 65,000 Park Water System - First mortgage bonds	100,003	—
U.S.\$ 70,000 Calpeco Electric System - Senior unsecured notes	90,130	96,015
U.S.\$ 50,000 Liberty Water Co - Senior unsecured notes	64,285	68,488
U.S.\$ 22,500 Park Water System - Non-revolving term credit facility	29,221	—
U.S.\$ 19,500 New England Gas System - First mortgage bonds	30,013	32,130
U.S.\$ 15,000 Granite State Electric System - Senior unsecured notes	19,453	20,730
U.S.\$ 827 Bella Vista Water System - Loans	1,073	1,213
	\$ 1,856,594	\$ 1,486,795
Less: current portion	(9,856)	(8,945)
	\$ 1,846,738	\$ 1,477,850

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***7. Long-term debt (continued)**

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to the Company. The loans 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.

Corporate

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.

APUC has a senior unsecured revolving credit of \$65,000 which was undrawn as at March 31, 2016. During the 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 months ended March 31, 2016 is \$979.

Distribution Group

On January 8, 2016, the Company assumed U.S. \$91,450 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. \$3,950 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		OPEB	
	Three months ended March 31,		Three months ended March 31,	
	2016	2015	2016	2015
Service cost	\$ 2,030	\$ 1,625	\$ 815	\$ 720
Interest cost	3,376	2,282	921	662
Expected return on plan assets	(3,512)	(2,840)	(319)	(189)
Amortization of net actuarial loss (gain)	656	298	131	33
Amortization of prior service credits	(151)	(32)	(477)	—
Amortization of regulatory asset/liability	1,142	1,247	267	293
Net benefit cost	\$ 3,541	\$ 2,580	\$ 1,338	\$ 1,519

9. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	March 31, 2016	December 31, 2015
Advances in aid of construction	\$ 127,808	\$ 92,285
Environmental remediation obligation	64,838	71,529
Asset retirement obligations	17,090	17,799
Customer deposits	14,634	15,074
Deferred income	12,092	13,682
Deferred credits	22,830	24,110
Other	42,683	25,277
	301,975	259,756
Less current portion	(36,470)	(36,621)
	\$ 265,505	\$ 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	357,999
Amortization of deferred financing costs	(49)
Carrying value at March 31, 2016	\$ 357,950
Face value at March 31, 2016	\$ 413,425

On March 1, 2016, the Company completed the sale of \$1,000,000 aggregate principal amount of 5.0% convertible unsecured subordinated 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 \$24,951, 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 will 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 months ended March 31, 2016 is \$4,884.

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 under stock option exercise, net of withholding taxes	2,720,980
Issuance of shares under the dividend reinvestment and employee share compensation plans	322,057
Common shares, end of period	258,912,456

(b) Share-based compensation

On March 31, 2016, the Board of Directors of APUC (the "Board") approved the grant of 2,487,601 options to executives of the Company. The options allow for the purchase of common shares at a price of \$10.82, 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.

During the three months period ended March 31, 2016, 16,691 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.

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.

For the three months period ended March 31, 2016, APUC recorded \$1,010 (2015 - \$872) 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 March 31, 2016, total unrecognized compensation costs related to non-vested options and PSUs were \$8,939 and \$1,543, respectively, and are expected to be recognized over a period of 2.36 and 1.42 years, respectively.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***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	(136,274)	25,124	25	(91)	(111,216)
Amounts reclassified	—	(3,558)	—	159	(3,399)
Net current period OCI	\$(136,274)	\$ 21,566	\$ 25	\$ 68	\$(114,615)
Balance, March 31, 2016	\$ 125,083	\$ 60,895	\$ (47)	\$ (13,809)	\$ 172,122

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 months ended March 31 were as follows:

	2016		2015	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	\$ 34,960	\$ 0.1287	\$ 27,807	\$ 0.1108
Series A preferred shares	\$ 1,350	\$ 0.2813	\$ 1,350	\$ 0.2813
Series D preferred shares	\$ 1,250	\$ 0.3125	\$ 1,250	\$ 0.3125

14. Related party transactions*Emera Inc.*

A member of the Board of APUC is an executive at Emera. For the three months ended March 31, 2016, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S.\$2,606 (2015 - U.S.\$1,592). For the three months ended March 31, 2016, Liberty Utilities purchased natural gas amounting to U.S. \$1,913 (2015 - U.S.\$131) 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.

There was U.S.\$261 included in accruals for the three months ended March 31, 2016 (December 31, 2015 - U.S. \$261) related to these transactions.

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees \$748 (2015 - \$394) during the three months ended March 31, 2016.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***15. Non-controlling interests**

Net loss attributable to non-controlling interests for the three months ended March 31 consists of the following:

	2016	2015
Net loss attributable to Class A partnership units	(13,431)	(8,862)
Other net earnings attributable to non-controlling interests	1,687	577
Total net loss attributable to non-controlling interests	\$ (11,744)	\$ (8,285)

16. Income taxes

For the three months ended, March 31, 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, recognition of deferred credits and non-deductible expenses.

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 months ended March 31 are as follows:

	2016	2015
Net earnings attributable to shareholders of APUC	\$ 42,036	\$ 43,106
Series A Preferred shares dividend	1,350	1,350
Series D Preferred shares dividend	1,250	1,250
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	\$ 39,436	\$ 40,506
Weighted average number of shares		
Basic	268,565,782	250,776,336
Effect of dilutive securities	3,566,763	3,114,464
Diluted	272,132,545	253,890,800

The shares potentially issuable as a result of 3,937,340 share options (2015 - \$Nil) 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.

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 is 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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***18. Segmented information (continued)**

	Three months ended March 31, 2016			
	Generation	Distribution	Corporate	Total
Revenue	\$ 72,362	\$ 269,383	\$ —	\$ 341,745
Fuel, power and water purchased	5,615	106,719	—	112,334
Net revenue	66,747	162,664	—	229,411
Operating expenses	16,280	68,500	322	85,102
Administrative expenses	3,471	5,430	2,517	11,418
Depreciation and amortization	21,388	28,337	—	49,725
Gain on foreign exchange	—	—	(302)	(302)
Operating income (loss) from continuing operations	25,608	60,397	(2,537)	83,468
Interest expense	5,943	12,724	6,396	25,063
Interest, dividend, equity and other income	(514)	(1,122)	(960)	(2,596)
Other expenses	289	6,048	5,868	12,205
Earnings (loss) before income taxes	\$ 19,890	\$ 42,747	\$ (13,841)	\$ 48,796
Property, plant and equipment	1,819,708	2,123,177	64,519	4,007,404
Equity-method investees	44,381	884	1,808	47,073
Total assets	2,293,023	3,183,651	138,780	5,615,454
Capital expenditures	42,396	36,084	2,425	80,905

	Three months ended March 31, 2015			
	Generation	Distribution	Corporate	Total
Revenue	\$ 63,652	\$ 318,202	\$ —	\$ 381,854
Fuel, power and water purchased	13,423	184,291	—	197,714
Net revenue	50,229	133,911	—	184,140
Operating expenses	15,107	55,682	371	71,160
Administrative expenses	4,386	6,791	(730)	10,447
Depreciation and amortization	16,890	18,702	795	36,387
Gain on foreign exchange	—	—	(1,243)	(1,243)
Operating income (loss) from continuing operations	13,846	52,736	807	67,389
Interest expense	8,625	7,546	462	16,633
Interest, dividend and other income	(1,037)	(415)	(1,003)	(2,455)
Other expense (gain)	(1,669)	273	395	(1,001)
Earnings before income taxes	\$ 7,927	\$ 45,332	\$ 953	\$ 54,212
Capital expenditures	20,397	23,540	1,464	45,401

December 31, 2015				
Property, plant and equipment	1,895,617	1,914,980	63,087	3,873,684
Equity-method investees	44,638	769	7,066	52,473
Total assets	2,345,905	2,532,894	112,926	4,991,725

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***19. Commitments 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 \$6,850. 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) 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 March 31, 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	\$ 60,534	\$ 50,026	\$ 52,879	\$ 55,832	\$ 39,763	\$ —	\$ 259,034
Gas supply and service agreements	61,850	44,744	36,310	32,754	26,163	73,092	274,913
Service agreements	36,184	35,191	32,664	33,904	34,040	479,766	651,749
Capital projects	190,255	29,416	589	367	67	17	220,711
Operating leases	5,824	5,709	5,338	5,068	5,118	108,787	135,844
Total	\$354,647	\$165,086	\$127,780	\$127,925	\$105,151	\$661,662	\$1,542,251

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***20. Non-cash operating items**

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

	2016	2015
Accounts receivable	\$ 13,619	\$ (55,055)
Natural gas in storage	16,621	22,306
Supplies and consumable inventory	310	(558)
Income taxes receivable	(3,762)	(25)
Prepaid expenses	(3,972)	(9,580)
Accounts payable	(35,706)	(47,265)
Accrued liabilities	(36,199)	(43,354)
Current income tax liability	(604)	(1,660)
Net regulatory assets and liabilities	2,994	37,929
	\$ (46,699)	\$ (97,262)

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments**

(a) Fair value of financial instruments

March 31, 2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 208,997	\$ 208,201	\$ —	\$ 208,201	\$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	90,763	90,763	—	—	90,763
Currency forward contract not designated as a hedge	3,490	3,490	—	3,490	—
Commodity contracts for regulated operations	9	9	—	9	—
Total derivative financial instruments	94,262	94,262	—	3,499	90,763
Total financial assets	\$ 303,259	\$ 302,463	\$ —	\$ 211,700	\$ 90,763
Long-term debt	\$ 1,856,594	\$ 1,946,047	\$ 506,257	\$ 1,439,790	\$ —
Convertible debentures	357,950	413,425	413,425	—	—
Preferred shares, Series C	18,485	17,571	—	17,571	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	79,902	79,902	—	79,902	—
Interest rate swap designated as a hedge	16,891	16,891	—	16,891	—
Currency forward contract not designated as a hedge	157	157	—	157	—
Commodity contracts for regulated operations	410	410	—	410	—
Total derivative financial instruments	97,360	97,360	—	97,360	—
Total financial liabilities	\$ 2,330,389	\$ 2,474,403	\$ 919,682	\$ 1,554,721	\$ —

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***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

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)****(a) Fair value of financial instruments (continued)**

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of March 31, 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 \$9.97 to \$114.70 with a weighted average of \$36.24 as of March 31, 2016. 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 months ended March 31, 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	577,469
Gas options	273,909
	851,378

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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)**

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

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:

	March 31, 2016	December 31, 2015
Regulatory assets:		
Gas swap contracts	U.S. \$ 226	U.S. \$ 1,058
Gas option contracts	U.S. \$ 89	U.S. \$ 154
Regulatory liabilities:		
Gas swap contracts	U.S. \$ 7	U.S. \$ 3
Gas option contracts	U.S. \$ —	U.S. \$ —

(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)
39,893	December 2016	\$ 68.56	AESO
762,958	December 2022	U.S. \$ 42.81	PJM Western HUB
3,271,173	December 2022	U.S. \$ 30.25	NI HUB
3,885,403	December 2027	U.S. \$ 36.46	ERCOT North HUB

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 gain of \$14,425 for the three months ended March 31, 2016 (2015 - loss of \$4,609), which is recorded in OCI.

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

	Three months ended March 31, 2016	2015
Effective portion of cash flow hedge, loss (gain)	\$ 25,134	\$ 6,838
Amortization of cash flow hedge	(10)	(9)
Loss (gain) reclassified from AOCI	(3,558)	(385)
OCI attributable to shareholders of APUC	\$ 21,566	\$ 6,444

The Company expects \$15,582 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.

21. Financial instruments (continued)**(b) Derivative instruments (continued)****(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 for the three months ended March 31, 2016 (2015 - \$Nil) was recorded in OCI.

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 months ended March 31, 2016 a loss of \$1,236 (2015 - loss of \$29,286) was recorded in OCI.

(iv) Other derivatives

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 through 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 is mitigated through the use of currency forward contracts to sell a net amount of U.S. \$123,400 for \$163,578 between April 29, 2016 and June 29, 2016. As of March 31, 2016, the estimated fair value of the instruments was an asset of \$3,489 and a liability of \$157. These currency forward contracts were not accounted for as a hedges.

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.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

March 31, 2016 and 2015

*(in thousands of Canadian dollars, except as noted and per share amounts)***21. Financial instruments (continued)**

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

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

	Three months ended March 31,	
	2016	2015
Change in unrealized loss (gain) on derivative financial instruments:		
Interest rate swaps	\$ —	\$ (357)
Energy derivative contracts	(426)	453
Currency forward contract	(5,250)	—
Total change in unrealized loss (gain) on derivative financial instruments	\$ (5,676)	\$ 96
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	—	469
Energy derivative contracts	970	(647)
Total realized loss (gain) on derivative financial instruments	\$ 970	\$ (178)
Loss (gain) on derivative financial instruments not accounted for as hedges	(4,706)	(82)
Ineffective portion of derivative financial instruments accounted for as hedges	398	(15)
	\$ (4,308)	\$ (97)
Amounts recognized in the unaudited interim consolidated statements of operations consist of:		
Loss (gain) on derivative financial instruments	\$ 942	\$ (97)
Gain on foreign exchange	\$ (5,250)	\$ —
	\$ (4,308)	\$ (97)

NOTES

NOTES

CORPORATE INFORMATION

DIRECTORS

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.

Christopher Ball – Executive Vice-President, Corpfinance International Ltd.

Christopher Huskison – President & Chief Executive Officer, Emera Inc.

Chris Jarratt – Vice-Chair, Algonquin Power & Utilities Corp.

Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.

George Steeves – Principal, True North Energy

Masheed Saidi – Former Executive VP and Chief Operating Officer, US Transmission, National Grid USA

Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy

THE MANAGEMENT GROUP

Ian Robertson, Chief Executive Officer

Chris Jarratt, Vice-Chair

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