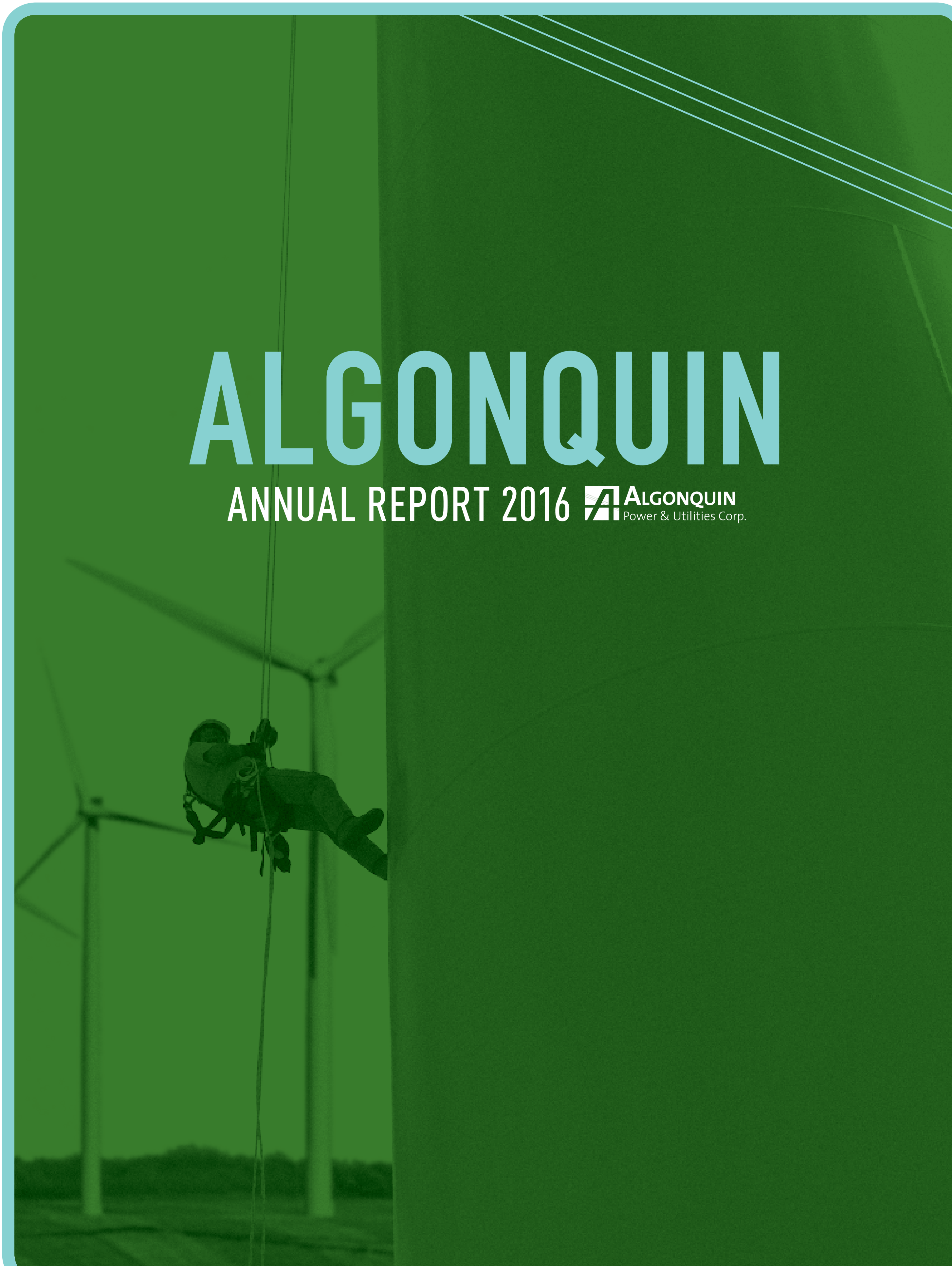
ALGONQUIN

ANNUAL REPORT 2016

Algonquin Power & Utilities Corp.



ALGONQUIN POWER & UTILITIES CORP.

UNDENIABLE STRENGTH: Algonquin Power & Utilities Corp. is a North American diversified generation, transmission and distribution utility with more than $10 billion of total assets.

CLEAR VISION: To be the utility company most admired by customers, communities and investors for its people, passion and performance.

Algonquin Power & Utilities Corp.

ALGONQUINPOWERANDUTILITIES.COM TORONTO STOCK EXCHANGE: AQN NEW YORK STOCK EXCHANGE: AQN

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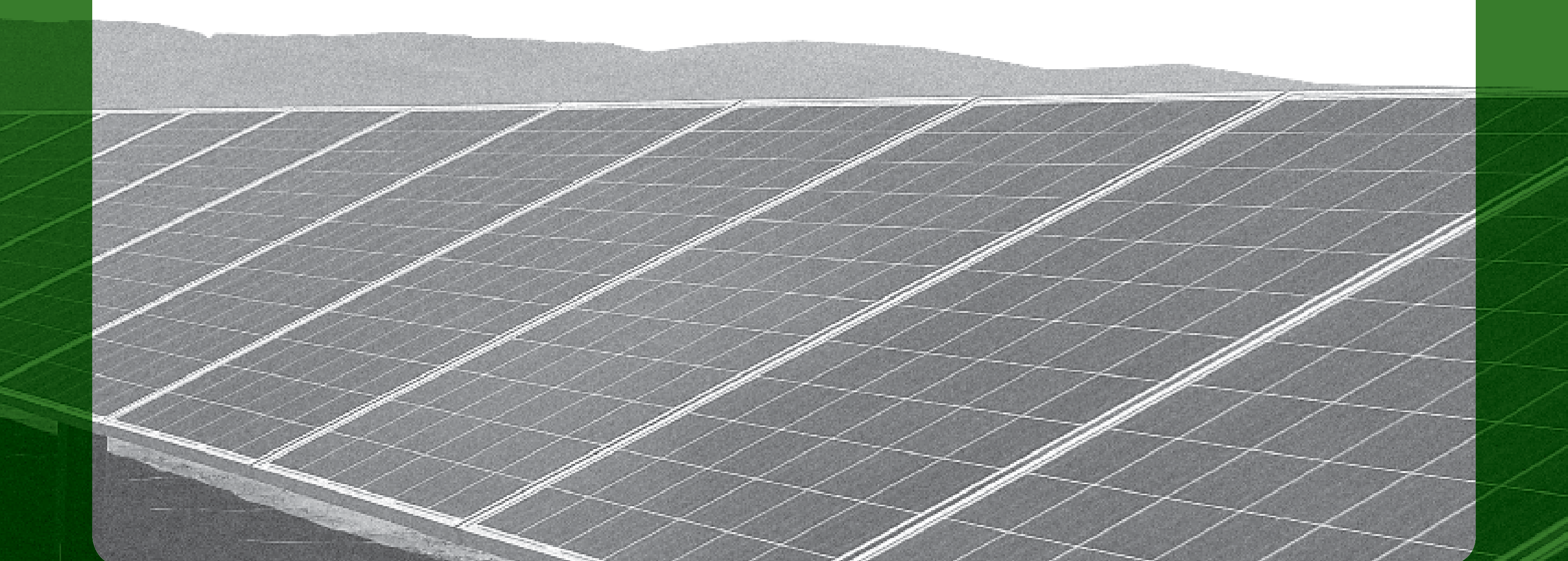


DIVERSIFIED ACROSS THE UTILITY VALUE SPECTRUM

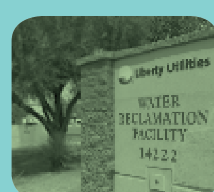
Algonquin Power & Utilities Corp. ("APUC") is a diversified utility company operating across the generation, transmission and distribution value spectrum. Through its two business groups, APUC owns and operates a diversified portfolio of North American rate-regulated and non-regulated electricity, natural gas and water utility businesses.

Rate-Regulated Utility Services

The Liberty Utilities business group is APUC's national rate-regulated generation, transmission and distribution utility which provides electricity, natural gas, and water utility services to close to 800,000 customers in 13 U.S. states. With the acquisition of The Empire District Electric Company ("Empire"), the rate-regulated asset portfolio now includes 1.3 GW of generation capacity dedicated to satisfying the electricity needs of Liberty Utilities' distribution customers. Liberty Utilities is committed to reducing customer costs through increased efficiencies and a prudent increase in the amount of renewable energy within the electricity mix delivered to customers. The expanded transmission businesses now include 1,200 miles of electrical transmission lines and 100 miles of natural gas transmission pipelines. Liberty Utilities is focused on delivering increased efficiencies to customers through continued investment in its utility systems and accretive acquisitions, representing more than US$3 billion in near term investment.

Renewable Electrical Generation

APUC's Liberty Power business group generates and sells electricity produced by its diversified portfolio of North American renewable and clean energy power generation facilities. Liberty Power's portfolio of non-regulated generation facilities includes more than 1.5 GW of hydroelectric, wind, solar, and natural gas fired generating capacity, delivering renewable and clean energy under long term off-take agreements. Liberty Power delivers increasing shareholder value through the development of new greenfield power generation projects, representing more than $2 billion in near term investment.



INCREASED SCALE WITH EMPIRE

On January 1, 2017, APUC completed the acquisition of Empire, a rate-regulated water, gas and electric utility serving 218,000 customers in Missouri, Arkansas, Oklahoma, and Kansas. The completion of this transaction materially expanded APUC's utility operations: today, over 2,200 employees are now dedicated to reliably meeting the needs of almost 800,000 electricity, natural gas, and water utility customers in 13 U.S. states.

The acquisition of Empire complements APUC's current business, bringing valuable scale to the rate-regulated utility sector, significant accretion to consolidated earnings and cash flows, and significant expansion to APUC's portfolio of exciting growth prospects.

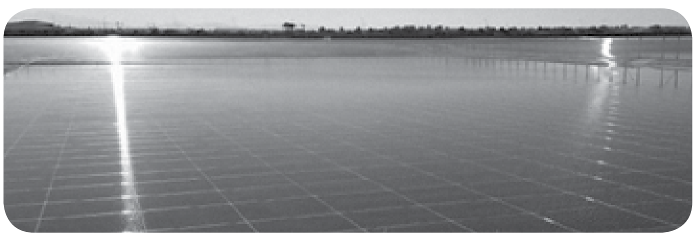
2016 FINANCIAL ACHIEVEMENTS

APUC is led by an experienced executive management team that has a long term, successful track record of growing the business. In 2016, APUC continued this trend by accomplishing the following:

65%
Asset Growth

27%
EBITDA[1] Growth

24%
Growth in Adjusted Funds from Operations[1]



24%
Growth in Adjusted Net Earnings Per Share[1]

10%
Dividend Increase

9.5%
Annual Total Shareholder Return

Annual revenues for 2017 are expected to exceed $2 billion from APUC's asset portfolio of more than $10 billion.* APUC's current market capitalization is approaching $5 billion.

*Please refer to the Forward-Looking Statements and Forward-Looking Information disclaimer on page 15.

2016 FINANCIAL HIGHLIGHTS

(in C$ millions)

Revenue	2016	2015	2014
Generation Revenue	243.1	222.6	202.3
Distribution Revenue	815.5	766.3	717.1
Other	37.4	39.0	22.2
Total Revenue	**1,096.0**	**1,027.9**	**941.6**
Adjusted EBITDA[1]	**476.9**	**375.4**	**290.5**
Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations	355.8	287.4	206.5
Adjusted Net Earnings	161.6	121.5	88.2
Per Share	0.57	0.46	0.37
Dividends to Shareholders	149.2	124.8	82.9
Per Share	0.55	0.49	0.37
Balance Sheet Data			
Total Assets	8,249.5	4,991.7	4,102.8
Long-Term Liabilities (includes current portion)	4,272.0	1,486.8	1,271.7
Number of Shares Outstanding as of Dec. 31	274,087,018	255,869,419	238,149,468
Renewable Energy Production (% of long term average)	**94%**	**93%**	**98%**
Utility Connections	**783,000**	**560,000**	**488,000**

[1] **Non-GAAP Financial Measures**
The terms "EBITDA", "adjusted EBITDA", "adjusted net earnings", "adjusted net earnings per share", and "adjusted funds from operations" (together, the "Financial Measures") are used throughout this Annual Report. The Financial Measures are not recognized measures under GAAP. There is no standardized measure of the Financial Measures, 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 these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.

SAFETY AND RISK AT THE FOREFRONT

Safety is embedded in the APUC culture and governs every aspect of business activity, each and every day. The organization is dedicated to creating a safe working environment and developing systems that ensure the safety of our employees, customers, and communities.

APUC's underlying safety belief is that "every accident is preventable"; the enduring commitment embodied in APUC's "Drive to Zero" program is to operate the businesses with zero lost time injuries. APUC is confident that the commitment is paying off, with the organization achieving world class lost time accident levels and, most notably, zero lost time injuries within APUC's renewable generation business group in 2016.

In 2016, APUC continued its journey to inculcate risk-oriented thinking into its operations and management teams. Enterprise-wide training has helped the APUC team ensure that risks are identified, analyzed and mitigated to optimize the likelihood of favourable business outcomes.

APUC BY THE NUMBERS

25
provinces and states

783,000
utility customers

2,200
employees

2,800
MW installed electric generating capacity

16
year average contract length of power purchase agreements

14,531
km of gas distribution lines

20,429
km of electricity distribution lines

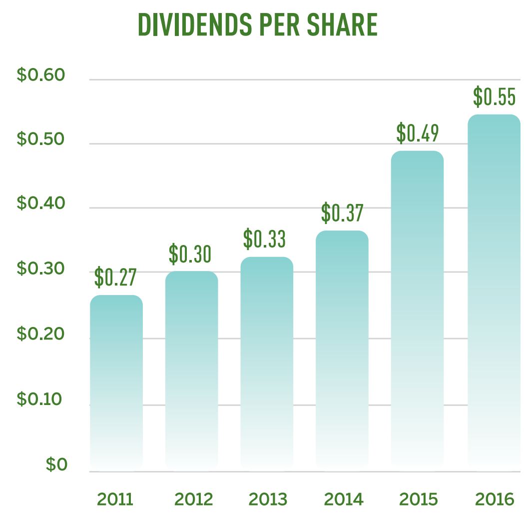
3,549
km of water distribution mains

494,046
solar panels

687
wind turbines**

59
hydroelectric generators

*Information on this page is as of January 1, 2017 and includes Empire. **Owned and/or contracted.



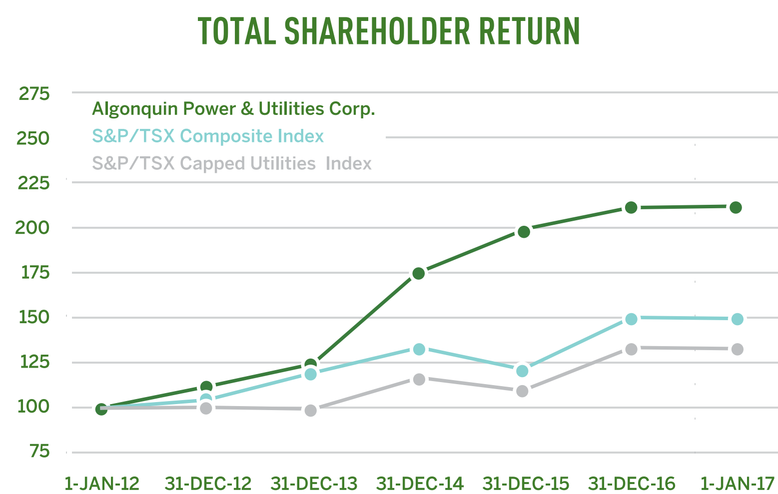
LETTER TO SHAREHOLDERS

Dear Fellow Shareholders,

Our vision remains clear: to be the utility company most admired by our customers, communities and investors for our people, passion, and performance. This past year marked an important milestone in the continued evolution of Algonquin Power & Utilities Corp. as a leading North American utility company.

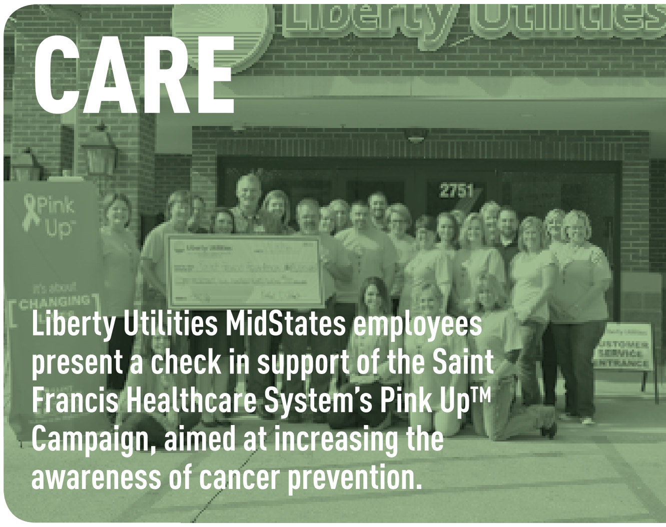
FINANCIAL ACHIEVEMENTS EXCEED EXPECTATIONS

We strongly believe in the old adage "Say what you are going to do, and then do what you say"... We are pleased that, once again in 2016, we were able to deliver strong performance against the goals we set for our businesses and the teams that lead them. From a financial perspective, the numbers speak for themselves, with year over year growth in both per share adjusted net earnings and adjusted funds from operations of close to 25%.



As a company we remain committed to providing our shareholders with a competitive and compelling value proposition: a safe and growing dividend coupled with accretive per share earnings growth. Consistent with this proposition, increasing per share earnings and cash flows underpinned our Board of Directors' approval of a 10% dividend increase in May, 2016, and again in January, 2017 following the completion of the acquisition of The Empire District Electric Company ("Empire"). We are proud that our financial performance has now supported seven consecutive years of double-digit dividend growth, a pattern we are focused on continuing going forward.

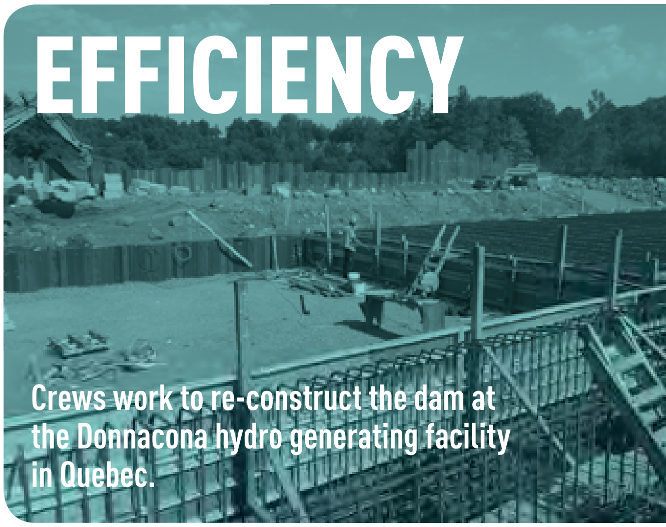
We acknowledge that share price performance over 2016 suffered from the short term effects of our growth initiatives; the issuance in February last year of $1.15 billion in deferred equity securities related to the Empire transaction appears to have had a temporary muting effect on share price as the financing was absorbed into the market, despite what we view as strong fundamental investor interest in APUC. With the conversion of such deferred equity into common shares now complete following the acquisition of Empire, we are confident that our strong fundamentals and proven track record of execution will be more accurately reflected in our share price.



Liberty Utilities MidStates employees present a check in support of the Saint Francis Healthcare System's Pink Up™ Campaign, aimed at increasing the awareness of cancer prevention.

AN EXCEPTIONAL YEAR FOR OUR LIBERTY UTILITIES GROUP

Since the formation in 2001 of our nation-wide diversified utility group, Liberty Utilities, we have made significant strides in building our capabilities, strengthening our customer and stakeholder relationships, and delivering stable and consistent growth to our shareholders. Our continued dedication to our corporate values of Care, Quality, and Efficiency have generated positive outcomes for our customers and for Liberty Utilities. Significantly, the acquisition of Empire represented a transformative milestone on our "March to a Million" utility customers; one which we anticipate will have a welcome and profound impact on APUC's growth and maturation as a company.



Crews work to re-construct the dam at the Donnacona hydro generating facility in Quebec.

EMPIRE – A LANDMARK ACQUISITION

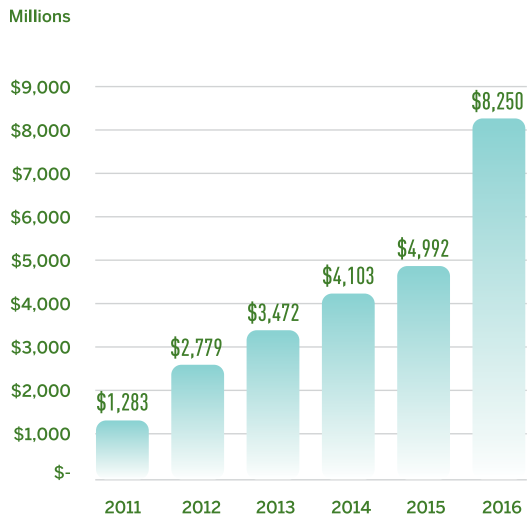
As an organization we are excited to have announced and then to have successfully secured all approvals necessary to close the Empire acquisition in 2016. The transaction, which officially closed on New Year's Day 2017, expands our customer base by close to 40%, and adds presence in complementary new regions and a diverse range of skills to our organization. As we welcome our new colleagues from Empire into the Liberty Utilities employee family, it has become increasingly apparent that we have added something far more valuable to APUC than just the 218,000 new utility customers previously served by Empire, making the combined organization stronger and more capable than ever.

Newly constructed walls of the Liberty Utilities Group's improvements to the Palm Valley Water Reclamation Facility in Arizona.

IMPORTANT NEW INVESTMENTS AND SYSTEM IMPROVEMENTS

Throughout Liberty Utilities, many successes were recorded as a result of the dedication and persistence of our employees to providing affordable, high quality services to all of our customers. An important benefit of our diverse U.S.-based utility operations is a reduction in the risks that would come from significant concentration in any one regulatory jurisdiction. In 2016, our regulatory team actively pursued rate cases in five separate states, providing an incremental U.S. $21.4 million in annual return on capital investments.

ASSETS



In 2016, Liberty Utilities capitalized on APUC's core competency in renewable energy through the addition of new solar electric generating capacity to our California-based electric utility. The completion of the 50 MW Luning solar facility stands as a positive example of the benefits of pursuing capital investment opportunities that lead to the 'win-win' of improved customer rates while at the same time reducing our operating expenses.

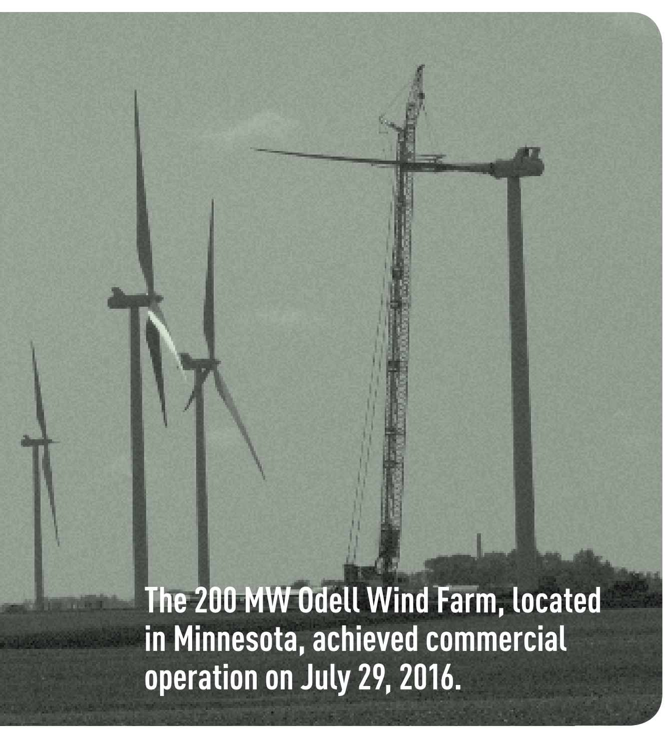
Liberty Utilities completed its acquisition of the Park Water utility business in early 2016, which serves 74,000 customers across three rate-regulated water utilities located in Southern California and Western Montana. While the integration of Park Water onto the Liberty Utilities platform has proceeded smoothly, the City of Missoula is continuing with its efforts to purchase the Montana utility from Liberty Utilities and we are preparing for the likelihood of such a sale.

SIGNIFICANT GROWTH IN OUR RENEWABLE GENERATION GROUP

Last year was highly active for Liberty Power, our non-regulated renewable generation business group; a year during which both project-specific and portfolio level milestones were reached. We are pleased to have now completed the commissioning of our 200 MW Odell Wind facility in Minnesota, the 150 MW Deerfield wind facility in Michigan, and the 10 MW Bakersfield II solar facility located in California. The long term off-take agreements associated with these new facilities extend our production-weighted average remaining contract life to 16 years. Notably, with the commissioning of the two new wind facilities, the installed capacity of our wind powered generating fleet now exceeds the one Gigawatt mark, an exciting milestone for the company.

Additional progress was made by Liberty Power on our development and construction-stage projects. Our 75 MW Ontario-based Amherst Island wind project secured a number of key approvals during the year, and construction activity related to the project has accelerated. We were also pleased to have reached agreement on an amended plan for our 177 MW Saskatchewan wind facility. Our 75 MW Great Bay solar project in Maryland entered construction and is expected to reach commercial operations in late 2017.

New initiatives announced in 2016 will also strengthen our ability to deliver medium term growth in our renewable generation portfolio. Of primary importance is our purchase of approximately $75 million of wind turbines that will qualify up to 700 MW of new wind generation projects for 100% of the production tax credits in the United States. This is an important step to sustain our competitiveness, and our power development teams are actively evaluating projects to maximize the value of this optionality.



The 200 MW Odell Wind Farm, located in Minnesota, achieved commercial operation on July 29, 2016.

Looking at our energy production within 2016, our diversification by modality had the desired effect of smoothing our results; higher hydrology in Canada acted to offset weaker wind resources for our U.S. wind facilities. We achieved significant growth in our operating profit from new facilities commissioned in 2016, along with the full-year contributions of both wind and solar projects commissioned in 2015. Our facilities achieved an impressive availability level of 98.1%, which once again demonstrates the capabilities of our operations teams to ensure our facilities perform at optimum levels when resource conditions are favourable.

The 150 MW Deerfield Wind facility, located in Central Michigan, achieved commercial operation in early 2017.

NYSE DEBUT

Among the milestones of 2016, the listing and commencement of trading for APUC's common shares on the New York Stock Exchange in November was a memorable highlight. The common shares of APUC now trade on both the Toronto Stock Exchange and the NYSE under the ticker symbol "AQN". Key to our decision to dual list our shares on the NYSE was the ability of our expanding number of U.S.-based employees to more comfortably participate in the ownership of our company through our employee share purchase plan. With our new presence on the NYSE, we also believe that the APUC value proposition is now more conveniently available to a broader audience of U.S. retail and institutional investors.

STRENGTH IN DIVERSITY

As a public commitment to gender diversity, we recently joined the 30% Club Canada, which is founded on the principle that stronger business performance and economic growth is positively correlated with the representation of women on boards and executive management teams. We are proud to report that more than 30% of our Board of Directors is represented by female leadership with the appointment of Melissa Stapleton Barnes in June 2016. We also further diversified our executive management team with the recent addition of Jennifer Tindale as Chief Legal Officer in early 2017.

Members of the Executive Management Team and Board of Directors ring the bell at the New York Stock Exchange on November 30, 2016.

OUR PLANS FOR THE FUTURE

We are confident that the stage is now set for new performance milestones to be achieved in 2017.

As articulated at our 2016 Investor Day, even excluding the $3.4 billion acquisition of Empire on January 1st of this year, our five year capital plan represents $6.3 billion in new investments, of which approximately $1.3 billion are expected to be completed during 2017. The recently completed commissioning of the Deerfield wind and Bakersfield II solar projects represent over $600 million towards our 2017 investment plan. Liberty Utilities is focused on completing

$670 million in new investment in its existing utility systems, a portion of which is committed to the newly integrated Empire operations. We are very excited about the new initiatives that have been set in motion and fully expect to be able to announce further signs of our progress on the delivery against our capital plan in 2017.

It's appropriate that we acknowledge and highlight an important new component to our business: the addition of over 1,300 MW of generating capacity dedicated to our regulated utility operations associated with the Empire acquisition. We believe there is a significant opportunity for customers of Empire to benefit from the substitution of renewable energy in place of the current coal generation in Empire's generation mix. This is a 'win-win' proposition that we will be discussing with the state regulators in 2017 – reduced customer energy costs while at the same time delivering environmental and societal benefits from a reduced carbon footprint.

OFFERING OUR THANKS

Our employees have built APUC and its businesses into highly reputable brands within the communities in which we operate, and we are grateful for the strong relationships our employees continue to cultivate with our customers, landowners, suppliers, local communities, and regulators. It is clearly evident that the true source of value creation within our organization is the entrepreneurial spirit and drive of our dedicated team of employees, including those that have recently joined us from Empire. Our sincere gratitude also goes to our Board of Directors, whose counsel has been invaluable as we deliver on our vision for the company. Our final thanks goes to our shareholders for the support they continue to provide us.

We are more committed than ever to our growth objectives and delivering continued strong returns to our shareholders in 2017 and beyond.

Ian Robertson
Chief Executive Officer

Ken Moore
Chairman of the
Board of Directors

Algonquin Power & Utilities Corp.

Management Discussion & Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2016. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2016 and 2015. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 10, 2017.

Caution Concerning Forward-looking Statements, Forward-looking Information and non-GAAP Measures

Forward-looking Statements and Forward-Looking Information

This MD&A may contain statements that, to the extent that they are not recitations of historical fact, constitute "forward-looking statements" or "forward-looking information" and within the meaning of applicable securities legislation, including the *United States Securities Act of 1933*, as amended, the *United States Securities Exchange Act of 1934*, as amended, and applicable Canadian Securities legislation (collectively referred to herein as "forward-looking information" or "forward-looking statements"). All forward-looking information and forward-looking statements are given pursuant to the "safe harbour" provisions of applicable securities legislation. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets as well as the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward-looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

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

Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under GAAP. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; 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", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

Use of Non-GAAP Financial Measures

Adjusted EBITDA

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

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. 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, which can be impacted positively or negatively by these items.

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 that are viewed as not directly related to a company's operating performance. 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 by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the Adjusted Funds from Operations of the entire facility is included in calculating the measure. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Net Energy Sales

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used 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 rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net Utility Sales

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

Divisional Operating Profit

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

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

Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4659 per common share per annum. Based on exchange rates as at March 1, 2017, the quarterly dividend is equivalent to Cdn $0.1554 per common share or Cdn $0.6216 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across two primary North American business units consisting of: the Renewable Generation Group which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and the Liberty Utilities Group which owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations.

Renewable Generation Group

The Renewable 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 Renewable 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 Renewable Generation Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 88% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which have a production-weighted average remaining contract life of 16 years.

The Renewable Generation Group also has a portfolio of development projects that when constructed will add approximately 351 MW of generation capacity from wind and solar powered generating facilities that have a production-weighted average contract life of 22 years.

Liberty Utilities Group

The Liberty Utilities Group operates diversified regulated electricity, natural gas, water distribution and wastewater collection utility services. The Liberty Utilities Group provides safe, high quality, and reliable services to its customers 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 Liberty Utilities Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

On January 1, 2017, Liberty Utilities Co., APUC's wholly-owned regulated utility business, completed the acquisition of The Empire District Electric Company ("Empire"). Empire is a vertically-integrated utility providing electric, natural gas and water service to approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

Including Empire, the Liberty Utilities Group now serves approximately 783,000 customers.

The Liberty Utilities Group's regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire. With the addition of Empire, the service territory has expanded into Missouri, Kansas, Oklahoma and Arkansas. The Liberty Utilities Group now serves approximately 264,000 electric connections.

The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri. With the expanded Missouri service area, the Liberty Utilities Group now serves approximately 336,000 natural gas connections.

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, Montana, and Texas; together serving approximately 183,000 connections.

With the integration of Empire, the Liberty Utilities Group now operates a fleet of regulated generation assets with a net capacity of 1,374MW.

2016 Major Highlights

Corporate Highlights

Completion of The Empire District Electric Company Acquisition

Subsequent to year end, on January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of Empire for an aggregate purchase price of approximately U.S. $2.4 billion including the assumption of approximately U.S. $0.9 billion of debt ("Empire Acquisition").

Empire is a Joplin, Missouri based regulated electric, gas and water utility that serves approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

With the closing of the Empire Acquisition, APUC has materially expanded its utility operations in the U.S.. APUC, through its 2,200 employees, now serves over 783,000 electric, gas, and water customers within its regulated utility business, and APUC's portfolio of power generating facilities now contains both regulated and non-regulated power facilities with a total generating capacity of over 2,500 MW.

APUC expects the Empire 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's increased contribution from regulated operations is also expected to further enhance the stability and predictability of the Company's Adjusted EBITDA, net earnings and quality of cash flows.

Annual dividend increased from U.S. $0.4235 to U.S. $0.4659 and

Declaration of Canadian Equivalent First Quarter Dividend of Cdn $0.1533 (U.S. $0.1165) per Common Share

APUC currently targets 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.

In addition to the completion of the Empire Acquisition in the first quarter of 2017, APUC 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. As a result, on January 16, 2017, the Board approved a dividend increase of U.S. $0.0424 per common share annually, bringing the total annual dividend to U.S. $0.4659 per common share, an increase of 10% over the previous annual dividend rate.

Concurrently, APUC declared a first quarter 2017 dividend of U.S. $0.1165 per common share payable on April 14, 2017 to shareholders of record on March 31, 2017. Based on the Bank of Canada noon exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2017 dividend is set at Cdn $0.1533 per common share.

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

	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Total
U.S. dollar dividend	$0.1059	$0.1059	$0.1059	$0.1165	$0.4342
Canadian dollar equivalent	$0.1361	$0.1377	$0.1427	$0.1533	$0.5698

Strong Year of Operating Results

APUC recorded a strong twelve months of operations results relative to the same period last year.

	Twelve Months Ended December 31		
(all dollar amounts in $ millions except per share information)	2016	2015	Change
Net earnings attributable to shareholders	**$130.9**	$117.5	**11%**
Adjusted Net Earnings	**$161.6**	$121.5	**33%**
Adjusted EBITDA	**$476.9**	$375.4	**27%**
Net earnings per common share	**$0.44**	$0.42	**5%**
Adjusted Net Earnings per common share	**$0.57**	$0.46	**24%**

Completion of Financing Related to the Acquisition

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

In the first quarter of 2016, in connection with the Acquisition, 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, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

Following the closing of the Acquisition, the final instalment date was established as February 2, 2017 at which time APUC received the final instalment payment. To date, approximately 99.1% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 107,517,895 common shares as a result of the conversion. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Acquisition ("Acquisition Facility").

U.S. $750 Million Private Placement Offering

On March 1, 2017, Liberty Utilities Group's financing entity entered into an agreement to issue U.S. $750 million of senior unsecured private placement notes to 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 3.6% after considering the effects of interest rate hedges entered into in 2016. The closing of the offering is scheduled to occur on March 24, 2017, with the proceeds to be used to repay the balance of the Acquisition Facility and other existing indebtedness.

See also *Empire District Electric Company Acquisition in the Regulatory Proceedings of the Liberty Utilities Group*

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

During the fourth quarter, APUC received approval to list its common shares for trading on the New York Stock Exchange ("NYSE"), and trading commenced on November 29, 2016, under the ticker symbol "AQN". The Company has been a U.S. Securities and Exchange Commission ("SEC") registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the Toronto Stock Exchange also under the ticker symbol "AQN".

U.S. $235 Million Corporate Term Credit Facility

On January 4, 2016, the Company entered into a U.S. $235.0 million term credit facility ("Corporate Term 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, 2018.

Renewable 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 Renewable Generation Group provides operation and supervisory 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 as of the exercise date, the financial results of the Red Lily Wind Facility are reported as part of the consolidated operations of APUC.

Completion of the Odell Wind Project

On July 29, 2016, the Odell Wind Facility achieved commercial operation ("COD"). The project consists of a 200 MW wind generating facility located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota. On August 5, 2016, tax equity financing of approximately U.S. $180 million was completed. The Odell Wind Facility is the Renewable Generation Group's ninth wind generating facility and consists of 100 Vestas V110-2.0 wind turbines. The facility is expected to generate 831.8 GW-hrs annually. The project has a 20 year power purchase agreement ("PPA") with Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the Midwest U.S..

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

Completion of the Deerfield Wind Project

Subsequent to year end, on February 21, 2017, the Deerfield Wind Facility achieved COD. The project consists of a 150 MW wind generating facility located in central Michigan. The Deerfield Wind Facility is the Renewable Generation Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. The project has a 20 year PPA with a local electric distribution utility serving approximately 260,000 customers in Michigan.

Completion of the Bakersfield II Solar Project

Subsequent to year end, on January 11, 2017, the Renewable Generation Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. $12.3 million was completed. The Bakersfield II Solar Facility is the Renewable Generation Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

Issuance of $300 million Senior Unsecured Debentures

Subsequent to year end, on January 17, 2017 the Renewable Generation Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Renewable Generation Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds have been used to partially finance the Odell Wind, Deerfield Wind and Bakersfield II Solar projects.

Purchase of Turbines to Safe Harbor Production Tax Credit Rate

At the end of 2016, the Renewable Generation Group purchased approximately $75 million of turbine components ("Safe Harbor Turbines") that will qualify between 500 MW and 700 MW of new projects for 100% of the production tax credit ("PTC"). The full PTC is approximately U.S. $23 per MWh and subject to an annual adjustment for inflation. The PTC at the full rate is available to projects in the United States completed before the end of 2020 if they commenced construction prior to December 31, 2016 or have purchased components that qualify under the Internal Revenue Service ("IRS") safe harbor rules ("Full PTC Projects"). Projects other than Full PTC Projects will receive 80% of the applicable PTC rate if construction commences in 2017, 60% if construction commences in 2018, and 40% if construction commences in 2019. Securing access to the full PTC rate is an important competitive advantage in the U.S. market. The Renewable Generation Group is currently evaluating projects to maximize the value of this equipment.

Liberty Utilities Group Highlights

Acquisition of the Park Water System

On January 8, 2016, the Liberty Utilities Group closed a previously announced agreement to acquire a regulated water distribution utility holding company, 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. $91.8 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. (See "Regulatory Risk Section: *Condemnation Expropriation Proceedings"* for further discussion.)

Completion of the Luning Solar Project.

Subsequent to year end, on February 15, 2017, the Liberty Utilities Group obtained control of a 50 MW solar generating facility located in Mineral County, Nevada for approximately U.S. $110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The project is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the project will be included in the rate base of the CalPeco Electric System as energy produced from the project will be consumed by the utility's customers.

Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2016, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $21.4 million. The Liberty Utilities Group has pending rate case filings in progress that represent an increase in rates in the amount of U.S. $14.1 million which are expected to be completed in 2017.

Completion of Phase I of the North Lake Tahoe Transmission System Upgrades

During 2016, the Liberty Utilities Group completed the rebuild of the 10 mile Northstar to Kings Beach, California transmission line for approximately U.S. $21.2 million. The rebuild involved an upgrade to 120 kv and will improve the reliability of the transmission system. The project is being completed in three phases and the total capital cost of the project will be included in the rate base of the utility. The second phase will result in an upgrade to substations and is expected to be in service in 2017.

2016 Fourth Quarter Results From Operations

Key Financial Information (all dollar amounts in $ millions except per share information)	Three Months Ended December 31 2016		2015	
Revenue	**$**	**310.2**	$	260.3
Net earnings attributable to shareholders from continuing operations		**46.3**		38.1
Net earnings attributable to shareholders		**46.3**		38.0
Cash provided by operating activities		**121.3**		94.3
Adjusted Net Earnings[1]		**51.4**		39.7
Adjusted EBITDA[1]		**138.3**		109.6
Adjusted Funds from Operations[1]		**95.8**		77.2
Dividends declared to common shareholders		**39.2**		34.0
Weighted average number of common shares outstanding		**273,952,963**		258,048,584
Per share				
Basic net earnings/(loss) from continuing operations	**$**	**0.16**	$	0.14
Basic net earnings/(loss)	**$**	**0.16**	$	0.14
Diluted net earnings/(loss)	**$**	**0.16**	$	0.14
Adjusted Net Earnings[1,2]	**$**	**0.18**	$	0.15
Dividends declared to common shareholders	**$**	**0.14**	$	0.13

1 Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2016, APUC experienced an average U.S. exchange rate of approximately $1.3343 as compared to $1.3351 in the same period in 2015. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2016, APUC reported total revenue of $310.2 million as compared to $260.3 million during the same period in 2015, an increase of $49.9 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2016 as compared to the corresponding period in 2015 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended December 31
Comparative Prior Period Revenue	**$**	**260.3**
RENEWABLE GENERATION GROUP		
Existing Facilities		
Hydro: Increase due to higher pricing recognized for certain Hydro-Quebec PPAs, offset by a decline in retail volumes and market pricing in the Maritime region.		—
Wind Canada: Increase due to higher production at St. Leon and Morse Wind Facilities resulting from strong wind resources, partially offset by the expiry of the Wind Power Production Incentive ("WPPI").		1.5
Wind U.S.: Decrease primarily due to lower market prices and production volumes.		(3.4)
Solar Canada: Decrease due to lower production at the Cornwall solar facility resulting primarily from lower realized irradiance.		(0.2)
Solar U.S.: Increase due to greater availability at the Bakersfield I Solar Facility resulting from unscheduled maintenance that occurred in the prior year.		0.1
Thermal: Increase primarily due to higher REC revenue and production at the Windsor Locks Thermal Facility, partially offset by lower production and pricing at the Sanger Thermal Facility.		0.5
Other		(0.3)
		(1.8)
New Facilities		
Wind U.S.: Acquisition of the Odell Wind Facility.		5.7
		5.7
Foreign Exchange		**—**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to reduced cost of energy which was partially offset by increased residential demand at the Granite State Electric System.		(3.7)
Gas: Increase primarily due to higher demand at the EnergyNorth and New England Gas Systems, and higher transportation revenues.		8.7
Water: Increase primarily due to higher consumption at the LPSCo and Bella Vista Water Systems.		0.4
Other: Increase primarily due to higher billings for contracted services.		5.9
		11.3
New Facilities		
Water: Acquisition of the Park Water System.		21.0
		21.0
Rate Cases		
Electricity: Implementation of new rates at the CalPeco Electric System retroactive to January 1, 2016.		11.9
Gas: Implementation of new rates at the Peach State and New England Gas Systems.		1.8
Water: Implementation of new rates at the Black Mountain Waste Water System and the Bella Vista and Rio Rico Water Systems.		0.6
		14.3
Foreign Exchange		**(0.6)**
Current Period Revenue	**$**	**310.2**

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

For the three months ended December 31, 2016, net earnings attributable to shareholders totaled $46.3 million as compared to $38.0 million during the same period in 2015, an increase of $8.3 million or 21.8%. The increase was due to a $25.5 million increase in earnings from operating facilities, $1.4 million increase in interest, dividend, equity and other income, $1.9 million decrease in losses on long lived assets, $12.9 million increase in gains from derivative instruments, $0.3 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses),* $0.1 million decrease in loss on discontinued operations, and $3.5 million increase in losses attributable to non-controlling interests. These items were partially offset by a $0.5 million increase in administration charges, $10.6 million increase in depreciation and amortization expenses, $1.0 million decrease in foreign exchange gain, $21.3 million increase in interest expense, $2.1 million decrease in other gains, and $1.8 million increase in acquisition costs as compared to the same period in 2015.

During the three months ended December 31, 2016, cash provided by operating activities totaled $121.3 million as compared to cash provided by operating activities of $94.3 million during the same period in 2015. During the three months ended December 31, 2016, Adjusted Funds from Operations totaled $95.8 million compared to Adjusted Funds from Operations of $77.2 million during the same period in 2015. The change in Adjusted Funds from Operations in the three months ended December 31, 2016 is primarily due to increased earnings from operations as compared to the same period in 2015.

Adjusted EBITDA in the three months ended December 31, 2016 totaled $138.3 million as compared to $109.6 million during the same period in 2015, an increase of $28.7 million or 26.2%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Performance Measures*).

2016 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31 2016	2015	2014
Revenue	**$ 1,096.0**	$ 1,027.9	$ 941.6
Net earnings attributable to shareholders from continuing operations	**130.9**	118.5	77.8
Net earnings attributable to shareholders	**130.9**	117.5	75.7
Cash provided by operating activities	**287.3**	261.9	192.7
Adjusted Net Earnings[1]	**161.6**	121.5	88.2
Adjusted EBITDA[1]	**476.9**	375.4	290.5
Adjusted Funds from Operations[1]	**355.8**	287.4	206.5
Dividends declared to common shareholders	**149.2**	124.8	82.9
Weighted average number of common shares outstanding	**271,832,430**	253,172,088	213,953,870
Per share			
Basic net earnings from continuing operations	**$ 0.44**	$ 0.43	$ 0.32
Basic net earnings	**$ 0.44**	$ 0.42	$ 0.31
Diluted net earnings	**$ 0.44**	$ 0.42	$ 0.31
Adjusted Net Earnings[1,2]	**$ 0.57**	$ 0.46	$ 0.37
Dividends declared to common shareholders	**$ 0.55**	$ 0.49	$ 0.37
Total assets	**8,249.5**	4,991.7	4,102.8
Long term debt[3]	**4,272.0**	1,486.8	1,271.7

1 Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

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

For the twelve months ended December 31, 2016, APUC experienced an average U.S. exchange rate of approximately $1.3253 as compared to $1.2786 in the same period in 2015. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2016, APUC reported total revenue of $1,096.0 million as compared to $1,027.9 million during the same period in 2015, an increase of $68.1 million or 6.6%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2016 as compared to the corresponding period in 2015 are set out as follows:

(all dollar amounts in $ millions)	Twelve Months Ended December 31	
Comparative Prior Period Revenue	**$**	**1,027.9**
RENEWABLE GENERATION GROUP		
Existing Facilities		
Hydro: Increase due to the recognition of rates from the Global Adjustment from Ontario Energy Financial Corporation ("OEFC"), improved hydrology during the year in the Quebec and Maritime regions and higher rates contained in new PPAs in the Quebec region.		10.0
Wind Canada: Decrease primarily due to expiry of the Canadian Federal Wind Power Production Incentive ("WPPI").		(0.7)
Wind U.S.: Decrease largely due to lower production at Minonk and Shady Oaks.		(3.4)
Solar Canada: Increase primarily due to increased production at the Cornwall Solar Facility due to higher irradiance as compared to the prior year.		0.1
Thermal: Decrease primarily due to lower gas prices which is a pass-through to customers as well as reduced demand for steam.		(3.3)
Other		(1.2)
		1.5
New Facilities		
Wind Canada: The Morse Wind Facility which achieved COD in April 2015.		4.1
Wind U.S.: Acquisition of the Odell Wind Facility.		7.0
Solar U.S.: The Bakersfield I Solar Facility achieved COD in April 2015 and experienced greater availability in the current year due to unscheduled maintenance that occurred in the prior year.		2.3
		13.4
Foreign Exchange		**6.2**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease due to reduced cost of energy at the Granite State Electric System which is a direct pass-through to customers.		(17.9)
Gas: Decrease due to reduced cost of gas and lower demand due to warmer winter weather experienced at the EnergyNorth, Peach State and Midstates and New England Gas systems.		(95.1)
Water: Increase is primarily due to higher consumption at the LPSCo and Bella Vista Water Systems.		3.1
Other: Decrease primarily due to lower revenues for contracted services and the sale of the water heater rental business in the New England Gas System.		(2.8)
		(112.7)
New Facilities		
Water: Acquisition of the Park Water System.		96.7
		96.7
Rate Cases		
Electricity: Implementation of new rates at the CalPeco Electric system retroactive to January 1, 2016 and interim rates at the Granite State Electric System.		12.7
Gas: Implementation of new rates at the EnergyNorth, Peach State, Illinois and New England Gas Systems.		10.7
Water: Implementation of new rates at the Pine Bluff, Rio Rico, Bella Vista water systems and the Black Mountain waste water system.		0.8
		24.2
Foreign Exchange		**38.8**
Current Period Revenue	**$**	**1,096.0**

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

For the twelve months ended December 31, 2016, net earnings attributable to shareholders totaled $130.9 million as compared to $117.5 million during the same period in 2015, an increase of $13.4 million. The increase was due to a $95.9 million increase in earnings from operating facilities, $1.5 million increase in interest, dividend, equity and other income, $3.5 million increase in Other Gains, $6.2 million decrease in losses on long lived assets, $13.7 million increase on gains from derivative instruments, $6.6 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*), $1.0 million decrease in loss on discontinued operations, and $6.6 million increase in losses attributable to non-controlling interests. These items were partially offset by $37.1 million increase in depreciation and amortization expenses, $6.5 million increase in administration charges, $2.2 million decrease in foreign exchange gains, $65.6 million increase in interest expense and $10.2 million increase in acquisition costs as compared to the same period in 2015.

During the twelve months ended December 31, 2016, cash provided by operating activities totaled $287.3 million as compared to cash provided by operating activities of $261.9 million during the same period in 2015. During the twelve months ended December 31, 2016, Adjusted Funds from Operations, a non-GAAP measure, totaled $355.8 million as compared to Adjusted Funds from Operations of $287.4 million the same period in 2015, an increase of $68.4 million.

Adjusted EBITDA in the twelve months ended December 31, 2016 totaled $476.9 million as compared to $375.4 million during the same period in 2015, an increase of $101.5 million or 27.0%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Performance Measures*).

2016 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Performance Measures*) in the three months ended December 31, 2016 totaled $138.3 million as compared to $109.6 million during the same period in 2015, an increase of $28.7 million or 26.2%. Adjusted EBITDA in the twelve months ended December 31, 2016 totaled $476.9 million as compared to $375.4 million during the same period in 2015, an increase of $101.5 million or 27.0%. The breakdown of Adjusted EBITDA by the company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units	**Three Months Ended December 31**		**Twelve Months Ended December 31**	
(all dollar amounts in $ millions)	**2016**	**2015**	**2016**	**2015**
Renewable Generation Group Operating Profit	**$ 61.9**	$ 62.0	**$ 217.3**	$ 188.8
Liberty Utilities Group Operating Profit	**87.1**	59.2	**302.4**	224.1
Administrative Expenses	**(13.1)**	(12.6)	**(46.3)**	(39.8)
Other Income & Expenses	**2.4**	1.0	**3.5**	2.3
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 138.3**	$ 109.6	**$ 476.9**	$ 375.4
Change in Adjusted EBITDA ($)	**$ 28.7**		**$ 101.5**	
Change in Adjusted EBITDA (%)	**26.2%**		**27.0%**	

Change in Adjusted EBITDA	**Three Months Ended December 31, 2016**			
(all dollar amounts in $ millions)	**Generation**	**Utilities**	**Corporate**	**Total**
Prior period balances	**$ 62.0**	**$ 59.2**	**$ (11.6)**	**$ 109.6**
Existing Facilities	(5.1)	6.2	1.5	2.6
New Facilities	5.4	7.7	—	13.1
Rate Cases	—	14.3	—	14.3
Foreign Exchange Impact	(0.4)	(0.3)	—	(0.7)
Administrative Expenses	—	—	(0.6)	(0.6)
Total change during the period	**$ (0.1)**	**$ 27.9**	**$ 0.9**	**$ 28.7**
Current period balances	**$ 61.9**	**$ 87.1**	**$ (10.7)**	**$ 138.3**

Change in Adjusted EBITDA	Twelve Months Ended December 31, 2016			
(all dollar amounts in $ millions)	Generation	Utilities	Corporate	Total
Prior period balances	**$ 188.8**	**$ 224.1**	**$ (37.5)**	**$ 375.4**
Existing Facilities	8.9	(1.4)	1.2	8.7
New Facilities	15.9	45.5	—	61.4
Rate Cases	—	24.2	—	24.2
Foreign Exchange Impact	3.7	10.0	—	13.7
Administration Expenses	—	—	(6.5)	(6.5)
Total change during the period	**$ 28.5**	**$ 78.3**	**$ (5.3)**	**$ 101.5**
Current period balances	**$ 217.3**	**$ 302.4**	**$ (42.8)**	**$ 476.9**

RENEWABLE GENERATION GROUP

2016 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2016	Three Months Ended December 31 2015	Long Term Average Resource	Twelve Months Ended December 31 2016	Twelve Months Ended December 31 2015
Hydro Facilities:						
Maritime Region	**37.6**	**21.9**	40.4	**148.2**	**144.1**	141.8
Quebec Region[1]	**72.6**	**64.0**	72.8	**273.9**	**267.5**	260.9
Ontario Region	**31.9**	**28.6**	34.3	**133.7**	**126.8**	140.7
Western Region	**12.6**	**18.1**	13.6	**65.0**	**66.1**	56.2
	154.7	**132.6**	161.1	**620.8**	**604.5**	599.6
Wind Facilities:						
St. Damase[2]	**22.7**	**20.4**	20.7	**76.9**	**74.4**	73.4
St. Leon	**121.4**	**130.8**	106.1	**430.2**	**417.3**	408.7
Red Lily[3]	**24.1**	**25.4**	20.7	**88.5**	**82.6**	78.8
Morse[4]	**30.5**	**27.7**	24.0	**108.8**	**94.8**	61.3
Sandy Ridge	**43.6**	**51.8**	43.7	**158.3**	**155.8**	150.0
Minonk	**189.7**	**184.9**	214.6	**673.7**	**635.8**	639.3
Senate	**140.0**	**136.7**	134.7	**520.4**	**504.4**	467.6
Shady Oaks	**100.5**	**104.4**	114.5	**355.6**	**323.9**	342.6
Odell[5]	**238.1**	**211.2**	—	**348.8**	**297.7**	—
	910.6	**893.3**	679.0	**2,761.2**	**2,586.7**	2,221.7
Solar Facilities:						
Cornwall	**2.2**	**1.9**	2.3	**14.7**	**15.6**	15.2
Bakersfield I[6]	**8.9**	**7.4**	6.4	**52.8**	**45.9**	32.7
	11.1	**9.3**	8.7	**67.5**	**61.5**	47.9
Renewable Energy Performance	**1,076.4**	**1,035.2**	848.8	**3,449.5**	**3,252.7**	2,869.2
Thermal Facilities:						
Windsor Locks	**N/A[7]**	**30.9**	25.5	**N/A[7]**	**131.0**	113.7
Sanger	**N/A[7]**	**28.8**	32.4	**N/A[7]**	**118.7**	129.8
		59.7	57.9		**249.7**	243.5
Total Performance		**1,094.9**	906.7		**3,502.4**	3,112.7

1 The Renewable Generation Group's 4.8 MW Donnacona Hydro Facility went offline in May 2015. Reconstruction of the Donnacona Dam has advanced to a stage where limited generation is occurring, and completion is expected in late second quarter of 2017.

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

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

4 The Morse Wind Facility achieved COD on April 22, 2015.

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

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

7 Natural gas fired co-generation facility.

2016 Fourth Quarter Generation Performance

For the three months ended December 31, 2016, the Renewable Generation Group generated 1,094.9 GW-hrs of electricity as compared to 906.7 GW-hrs during the same period of 2015.

For the three months ended December 31, 2016, the hydro facilities generated 132.6 GW-hrs of electricity as compared to 161.1 GW-hrs produced in the same period in 2015, a decrease of 17.7%. Electricity generated represented 85.7% of long-term average resources ("LTAR") as compared to 104.1% during the same period in 2015. During the quarter, increased generation in the Western region partly offsets declines in the Maritimes, Quebec and Ontario.

For the three months ended December 31, 2016, the wind facilities produced 893.3 GW-hrs of electricity as compared to 679.0 GW-hrs produced in the same period in 2015, an increase of 31.6%. The higher generation was primarily due to the first full quarter of production at the Odell Wind Facility (which achieved COD on July 29, 2016). This was partly offset by lower production at the Minonk and Shady Oaks Wind Facilities. During the three months ended December 31, 2016, the wind facilities (excluding the Odell Wind Facility) generated electricity equal to 101.3% of LTAR as compared to 100.9% during the same period in 2015.

For the three months ended December 31, 2016, the solar facilities generated 9.3 GW-hrs of electricity as compared to 8.7 GW-hrs of electricity in the same period in 2015, an increase of 6.9%. The increase in production is largely attributable to the Bakersfield I Solar Facility which was negatively impacted by unscheduled maintenance during the same period in 2015. Cornwall's production was 13.6% below its LTAR as compared to 4.5% above its LTAR in the same period in 2015.

For the three months ended December 31, 2016, the thermal facilities generated 59.7 GW-hrs of electricity as compared to 57.9 GW-hrs of electricity during the same period in 2015. During the same period, the Windsor Locks Thermal Facility generated 129.3 billion lbs of steam as compared to 155.0 billion lbs of steam during the same period in 2015.

2016 Annual Generation Performance

For the twelve months ended December 31, 2016, the Renewable Generation Group generated 3,502.4 GW-hrs of electricity as compared to 3,112.7 GW-hrs during the same period of 2015.

For the twelve months ended December 31, 2016, the hydro facilities generated 604.5 GW-hrs of electricity as compared to 599.6 GW-hrs produced in the same period in 2015, an increase of 0.8%. Electricity generated represented 97.4% of long-term projected average resources as compared to 96.3% during the same period in 2015. During the twelve months ended December 31, 2016, the Western region achieved production above its LTAR, while the Maritime, Quebec and Ontario regions were below their respective LTAR. The Quebec region achieved 106% of its LTAR excluding the Donnacona Hydro Facility which was offline during the period.

For the twelve months ended December 31, 2016, the wind facilities produced 2,586.7 GW-hrs of electricity as compared to 2,221.7 GW-hrs produced in the same period in 2015, an increase of 16.4%. During the twelve months ended December 31, 2016, the wind facilities generated electricity equal to 93.7% of LTAR as compared to 93.7% during the same period in 2015. The increase in production was primarily due to higher production at the Senate, St. Leon and Sandy Ridge Wind Facilities as well as the incremental electricity generated at the Morse and Odell Wind Facilities which achieved commercial operation on April 22, 2015 and July 29, 2016, respectively.

For the twelve months ended December 31, 2016, the solar facilities generated 61.5 GW-hrs of electricity as compared to 47.9 GW-hrs of electricity produced in the same period in 2015, an increase of 28.4%. The increase in production is attributable to a full year of production at the new Bakersfield I Solar Facility which achieved COD on April 14, 2015. The Cornwall Solar Facility's production was 6.1% above its LTAR as compared to 3.4% above its LTAR in the same period last year. The Bakersfield I Solar Facility's production was 13.1% below its LTAR.

For the twelve months ended December 31, 2016, the thermal facilities generated 249.7 GW-hrs of electricity as compared to 243.5 GW-hrs of electricity during the same period in 2015. During the same period, the Windsor Locks Thermal Facility generated 552.5 billion lbs of steam as compared to 613.0 billion lbs of steam during the same period in 2015.

2016 Renewable Generation Group Operating Results

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2016	2015	2016	2015
Revenue[1]				
Hydro	**$ 14.6**	$ 14.6	**$ 66.5**	$ 55.7
Wind	**42.6**	38.7	**128.2**	118.1
Solar	**1.6**	1.6	**12.9**	10.3
Thermal	**8.2**	8.1	**35.5**	38.5
Total Revenue	**$ 67.0**	$ 63.0	**$ 243.1**	$ 222.6
Less:				
Cost of Sales - Energy[2]	**(1.8)**	(1.7)	**(5.8)**	(10.3)
Cost of Sales - Thermal	**(4.4)**	(3.6)	**(15.5)**	(17.7)
Realized gain/(loss) on hedges[3]	**—**	—	**(1.0)**	0.6
Net Energy Sales[5]	**$ 60.8**	$ 57.7	**$ 220.8**	$ 195.2
Renewable Energy Credits ("REC")[4]	**6.3**	6.1	**20.2**	18.5
Other Revenue	**0.5**	0.7	**2.4**	2.5
Total Net Revenue	**$ 67.6**	$ 64.5	**$ 243.4**	$ 216.2
Expenses & Other Income				
Operating expenses	**(20.2)**	(15.0)	**(72.3)**	(63.6)
Interest, dividend, equity and other income	**(0.1)**	(0.7)	**1.4**	(0.4)
Operating Profit from non-Consolidated entities[5]	**1.0**	0.6	**3.8**	2.7
HLBV income[6]	**13.6**	12.6	**41.0**	33.9
Divisional Operating Profit[7,8]	**$ 61.9**	$ 62.0	**$ 217.3**	$ 188.8

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

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

3 See financial statements note 25(b)(iv).

4 Qualifying renewable energy projects receive Renewable Energy Credits ("REC") for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source.

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

6 HLBV income represents the value of net tax attributes earned by the Renewable Generation Group in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

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

8 See Non-GAAP Financial Measures.

2016 Fourth Quarter Operating Results

For the three months ended December 31, 2016, the Renewable Generation Group facilities generated $61.9 million of operating profit as compared to $62.0 million during the same period in 2015, which represents a decrease of $0.1 million, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31
Prior Period Operating Profit	**$ 62.0**
Existing Facilities	
Hydro: Increase due to higher realized pricing in Ontario and Quebec mainly offset by decreased production and retail demand.	0.1
Wind Canada: Increase in production at the St. Leon and Morse Wind Facilities due to an improved wind resource, partially offset by a decrease in rates due to the expiry of the WPPI at St. Leon Wind Facility.	1.2
Wind U.S.: Decrease primarily due to lower production at Minonk and Shady Oaks Wind Facilities and annual escalation in fees payable under operating and maintenance agreements.	(4.8)
Solar Canada: Decrease in production due to snow coverage and poor irradiance at the Cornwall Solar Facility.	(0.4)
Solar U.S.: Increase due to higher production and HLBV income at the Bakersfield I Solar Facility.	0.5
Thermal: Decrease due to production and basis pricing declines at the Sanger Thermal Facility.	(0.3)
Other: Decrease due to higher development costs, partially offset by a non-recurring equity loss recorded in the prior year.	(1.4)
	(5.1)
New Facilities	
Wind Canada: Incremental operating profit from the purchase of the Red Lily Wind Facility.	0.9
Wind U.S.: Acquisition of the Odell Wind Facility.	6.0
Solar U.S.: The Bakersfield II Solar Project was placed in service in December 2016 resulting in a recognition of HLBV loss and closing costs.	(1.5)
	5.4
Foreign Exchange	**(0.4)**
Current Period Divisional Operating Profit	**$ 61.9**

2016 Annual Operating Results

For the twelve months ended December 31, 2016, the Renewable Generation Group facilities generated $217.3 million of operating profit as compared to $188.8 million during the same period in 2015, which represents an increase of $28.5 million or 15.1%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	**$**	**188.8**
Existing Facilities		
Hydro: Increase primarily due to the receipt of the retroactive Global Adjustment payments ($8.4 million) from the OEFC and improved hydrology in the Quebec and Maritime regions, as well as a reduction in the volume and cost of energy purchased to satisfy retail load in the Maritime region.		13.4
Wind Canada: Decrease primarily due to lower realized rates resulting from the expiry of WPPI for the St. Leon Wind Facility.		(1.0)
Wind U.S.: Decrease primarily due to lower production at the Minonk and Shady Oaks Wind Facilities and annual escalation in fees under Operating and Maintenance contracts, partially offset by higher HLBV income due to the reduced economic interest of Tax Equity investors.		(2.1)
Solar Canada: Small increase in production at the Cornwall Solar Facility which was offset by an increase in operating costs.		—
Thermal: Decrease primarily due to reduced customer demand at the Sanger Thermal Facility, partly offset by declining fuel prices.		(0.8)
Other: Decrease primarily due to higher development costs offset by the interest earned on the OEFC's Global Adjustment payments and a non-recurring equity loss recorded in the prior year.		(0.6)
		8.9
New Facilities		
Wind Canada: The Morse Wind Facility achieved COD on April 22, 2015.		3.8
Wind Canada: Incremental operating profit from the acquisition of the Red Lily Wind Facility.		2.1
Wind U.S.: Acquisition of the Odell Wind Facility.		7.5
Solar U.S.: Full year results from the Bakersfield I Solar Facility which achieved COD in mid 2015.		2.5
		15.9
Foreign Exchange		**3.7**
Current Period Divisional Operating Profit	**$**	**217.3**

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 Renewable Generation Group's existing portfolio. The Development Division is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. The Renewable Generation Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that the Renewable Generation Group's Development Division will begin construction or execute an acquisition agreement.

The Renewable Generation Group's Development Division has successfully completed, is constructing, and is developing a number of power generation projects. The 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 objectives. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost (millions)[3]	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction						
Amherst Island Wind Project	Ontario	75	$ 295	2018	20	235
Great Bay Solar Project[1]	Maryland	75	195	2017	10	146
Total Projects in Construction		**150**	**$ 490**			**381**
Projects in Development						
Chaplin/Blue Hill Wind Project	Saskatchewan	177	$ 345	2019/20	25	813
Val-Eo Wind Project[2]	Quebec	24	65	2018	20	66
Total Projects in Development		**201**	**$ 410**			**879**
Total in Construction and Development		**351**	**$ 900**			**1,260**

1 The total cost of the project is expected to be approximately $145 million in U.S. dollars.

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

3 Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

Projects Recently Completed

Deerfield Wind Project

The Deerfield Wind Project is a 150.0 MW wind powered electric generating development project located in central Michigan and is 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. The project declared commercial operations on February 21, 2017.

The project is the Renewable Generation Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs of energy per year, with all energy, capacity, and renewable energy credits from the project sold to a local electric distribution utility which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

The Renewable Generation Group's interest in the project is via a 50% joint venture with the original developer along with an option to acquire the other 50% interest, subject to certain adjustments any time prior to the date that is 90 days following commencement of operations.

Bakersfield II Solar Project

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

Construction of the project commenced in the second quarter of 2015. The facility declared commercial operations on January 11, 2017.

The facility is the Renewable Generation Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

The project qualifies for U.S. federal investment tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects approximately U.S. $12.2 million of financing for the project was sourced from tax equity investors. The financing closed on February 28, 2017 following achievement of commercial operations.

Projects in Construction

Amherst Island Wind Project

The Amherst Island Wind Project is a 75.0 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is currently contemplated to use Class III wind turbine generator technology consisting of 26 Siemens 3.0 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually with all energy being sold under a 20 year PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority, Feed in Tariff ("FIT") program.

The total cost to complete the project is estimated at approximately $295 million.

The Renewable Energy Approval ("REA") was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment. An appeal of the REA was made to the Environmental Review Tribunal ("ERT") in 2015. The ERT decision to uphold the REA was issued on August 3, 2016. The project has since conducted final development and procurement efforts and is now under construction. A Divisional Court challenge of the favorable ERT decision was dismissed in the first quarter of 2017.

Since the REA decision, the Company procured the project turbines, submarine cable, and the main power transformer. Negotiations are in progress to engage the balance of plant constructor. Subject to receipt of final permits and negotiation of remaining agreements, final development and construction is expected to be complete in the second quarter of 2018.

Great Bay Solar

The Great Bay Solar Project is a 75.0 MW solar powered electric generating development project located in Somerset County in southern Maryland.

The facility is comprised of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All Solar Renewable Energy Credits from the project will be retained by the project company and sold into the Maryland market.

Permitting with the county is underway and is expected to be completed in the first quarter of 2017. The project has received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission. The balance of plant and high voltage engineering, procurement, and construction contracts have been executed. The project has a commercial operations date targeted for the end of 2017.

The total costs to complete the project are estimated at approximately U.S. $145.0 million. The Renewable Generation Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 40% of the permanent project financing is expected to be funded by tax equity investors in return for the majority of the tax attributes.

Projects in Development

Chaplin-Blue Hill Wind Project

The Chaplin-Blue Hill Wind Project is a 177.0 MW wind powered electric generating development project located in Saskatchewan. All of the energy from the project will be sold to SaskPower pursuant to a 25 year PPA awarded in 2012. The project was originally located in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

During the year the Saskatchewan Ministry of the Environment determined the original location proposed for the project did not meet its new siting guidelines for wind farms in the Province. As a result, SaskPower and the Company have worked to reconfigure the project in a manner that meets new siting guidelines in the rural municipalities of Morse and Lawtonia.

The Chaplin-Blue Hill project will be developed as a single phase installation beginning in early 2019. All energy from the facility will be sold to SaskPower pursuant to a 25 year PPA that was signed in December 2016. The project requires final environmental approval and all other necessary permitting.

The total costs to complete the project are estimated at approximately $345.0 million but are subject to change depending on turbine selection.

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 Renewable Generation Group.

The Renewable Generation Group's equity interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and, therefore, the project will be entitled to a refundable tax credit equal to approximately $18.0 million.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely be comprised of ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be 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 the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

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

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 565,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, Liberty Utilities completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. Including Empire, Liberty now serves approximately 783,000 customers. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities 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)	As at December 31 2016 Assets	2016 Total Connections[1]	2015 Assets	2015 Total Connections[1]
Electricity	**$ 378.4**	**94,000**	$ 343.2	93,000
Natural Gas	**845.9**	**293,000**	783.0	292,000
Water and Wastewater	**516.4**	**178,000**	254.7	104,000
Total	**$ 1,740.7**	**565,000**	$ 1,380.9	489,000
Accumulated Deferred Income Taxes Liability	**$ 194.7**		$ 110.3	

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

The Liberty Utilities 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 94,000 connections in the states of California and New Hampshire.

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

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

2016 Fourth Quarter Usage Results

Electric Distribution Systems

	Three Months Ended December 31 2016	2015
Average Active Electric Connections For The Period		
Residential	80,600	79,900
Commercial and industrial	12,500	12,300
Total Average Active Electric Connections For The Period	**93,100**	**92,200**
Customer Usage (GW-hrs)		
Residential	142.5	135.8
Commercial and industrial	225.0	220.3
Total Customer Usage (GW-hrs)	**367.5**	**356.1**

For the three months ended December 31, 2016 the electric distribution systems' usage totaled 367.5 GW-hrs as compared to 356.1 GW-hrs for the same period in 2015, an increase of 11.4 GW-hrs or 3.2%.

Natural Gas Distribution Systems

	Three Months Ended December 31	
	2016	2015
Average Active Natural Gas Connections For The Period		
Residential	248,100	247,500
Commercial and industrial	26,600	26,600
Total Average Active Natural Gas Connections For The Period	**274,700**	**274,100**
Customer Usage (MMBTU)		
Residential	3,737,000	3,002,000
Commercial and industrial	3,446,000	2,362,000
Total Customer Usage (MMBTU)	**7,183,000**	**5,364,000**

For the three months ended December 31, 2016, usage at the natural gas distribution systems totaled 7,183,000 MMBTU as compared to 5,364,000 MMBTU during the same period in 2015, an increase of 1,819,000 MMBTU, or 33.9%. The increase is primarily due to higher heating degree days in the three months ended December 31, 2016 as compared to the same period in the prior year.

Water and Wastewater Distribution Systems

	Three Months Ended December 31	
	2016	2015
Average Active Connections For The Period		
Wastewater connections	41,100	40,200
Water distribution connections	129,400	58,700
Total Average Active Connections For The Period	**170,500**	**98,900**
Gallons Provided		
Wastewater treated (millions of gallons)	542	532
Water sold (millions of gallons)	4,113	1,971
Total Gallons Provided	**4,655**	**2,503**

During the three months ended December 31, 2016, the water and wastewater distribution systems provided approximately 4,113 million gallons of water to its customers and treated approximately 542 million gallons of wastewater as compared to 1,971 million gallons of water provided and 532 million gallons of wastewater treated during the same period in 2015. The increase in the gallons of water provided to customers can be primarily attributed to the addition of the Park Water System on January 8, 2016. The Park Water system provided approximately 2,074 million gallons of water to customers during the three months ended December 31, 2016.

2016 Fourth Quarter Operating Results

	Three Months Ended December 31			
	2016 U.S. $ (millions)	2015 U.S. $ (millions)	2016 Can $ (millions)	2015 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 46.9**	$ 40.8	**$ 62.5**	$ 54.6
Less: cost of sales – electricity	**(20.6)**	(23.1)	**(27.5)**	(30.9)
Net Utility Sales - electricity	**26.3**	17.7	**35.0**	23.7
Utility natural gas sales and distribution	**85.1**	79.8	**114.0**	107.2
Less: cost of sales – natural gas	**(39.8)**	(36.4)	**(53.2)**	(48.9)
Net Utility Sales - natural gas	**45.3**	43.4	**60.8**	58.3
Utility water distribution & wastewater treatment sales and distribution	**31.7**	15.3	**42.3**	20.4
Less: cost of sales – water	**(2.2)**	—	**(3.0)**	—
Net Utility Sales - water distribution & wastewater treatment	**29.5**	15.3	**39.3**	20.4
Gas transportation	**8.4**	5.7	**10.7**	7.6
Other revenue	**5.0**	0.4	**6.8**	0.5
Net Utility Sales	**114.5**	82.5	**152.6**	110.5
Operating expenses	**(50.0)**	(39.2)	**(66.8)**	(52.4)
Other income	**0.9**	0.8	**1.3**	1.1
Divisional Operating Profit[1]	**$ 65.4**	$ 44.1	**$ 87.1**	$ 59.2

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

For the three months ended December 31, 2016, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $65.4 million as compared to U.S. $44.1 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was $87.1 million as compared to $59.2 million during the same period in 2015, which represents an increase of $27.9 million or 47%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31	
Prior Period Operating Profit	**$**	**59.2**
Existing Facilities		
Electricity: Decrease primarily related to higher operating expenses at the CalPeco and Granite State Electric systems.		(2.7)
Gas: Increase due to higher revenues at the EnergyNorth, Midstates, and Peach State Gas systems, largely due to higher heating degree days.		4.1
Water: Increase primarily related to higher consumption at the LPSCo and Bella Vista Water systems.		1.5
Other: Increase primarily due to higher revenues for contracted services.		3.3
		6.2
New Facilities		
Water: The acquisition of the Park Water System closed on January 8, 2016.		7.7
		7.7
Rate Cases		
Electricity: Implementation of new rates at the CalPeco Electric system retroactive back to January 1, 2016.		11.9
Gas: Implementation of new rates at the Peach State and New England Gas Systems.		1.8
Water: Implementation of new rates at the Black Mountain Waste Water System along with the Bella Vista and Rio Rico Water Systems.		0.6
		14.3
Foreign Exchange		**(0.3)**
Current Period Divisional Operating Profit	**$**	**87.1**

2016 Annual Usage Results

Electric Distribution Systems

	Twelve Months Ended December 31	
	2016	2015
Average Active Electric Connections For The Period		
Residential	80,400	79,900
Commercial and industrial	12,500	12,400
Total Average Active Electric Connections For The Period	**92,900**	**92,300**
Customer Usage (GW-hrs)		
Residential	567.0	555.0
Commercial and industrial	895.2	898.7
Total Customer Usage (GW-hrs)	**1,462.2**	**1,453.7**

For the twelve months ended December 31, 2016 the electric distribution systems' usage totaled 1,462.2 GW-hrs as compared to 1,453.7 GW-hrs for the same period in 2015, an increase of 8.5 GW-hrs. Customer usage at the Granite State Electric system decreased by approximately 21.1 GW-hrs due to warmer weather experienced in the region as compared to the prior year. This decrease was offset by increased customer usage at the CalPeco Electric System which was 29.6 GW-hrs higher as compared to the prior year.

Natural Gas Distribution Systems

	Twelve Months Ended December 31	
	2016	**2015**
Average Active Natural Gas Connections For The Period		
Residential	249,000	248,300
Commercial and industrial	26,600	26,700
Total Average Active Natural Gas Connections For The Period	**275,600**	**275,000**
Customer Usage (MMBTU)		
Residential	15,346,000	17,383,000
Commercial and industrial	12,768,000	12,460,000
Total Customer Usage (MMBTU)	**28,114,000**	**29,843,000**

For the twelve months ended December 31, 2016, usage at the natural gas distribution systems totaled 28,114,000 MMBTU as compared to 29,843,000 MMBTU during the same period in 2015, a decrease of 1,729,000 MMBTU or 5.8%. The decrease in natural gas usage as compared to the same period in 2015 can be primarily attributed to a decrease in heating degrees days experienced at the EnergyNorth, Midstates and New England Gas Systems service territories.

Water and Wastewater Distribution Systems

	Twelve Months Ended December 31	
	2016	**2015**
Average Active Connections For The Period		
Wastewater connections	41,100	40,100
Water distribution connections	131,400	58,800
Total Average Active Connections For The Period	**172,500**	98,900
Gallons Provided		
Wastewater treated (millions of gallons)	2,231	2,168
Water sold (millions of gallons)	17,936	8,457
Total Gallons Provided	**20,167**	10,625

During the twelve months ended December 31, 2016, the water and wastewater distribution systems provided approximately 17,936 million gallons of water to its customers and treated approximately 2,231 million gallons of wastewater as compared to 8,457 million gallons of water and 2,168 million gallons of wastewater during the same period in 2015. The increase in water provided can be primarily attributed to the acquisition of the Park Water System on January 8, 2016 which provided 7,471 million gallons of water during the year.

2016 Annual Operating Results

	Twelve Months Ended December 31			
	2016 U.S. $ (millions)	**2015 U.S. $ (millions)**	**2016 Can $ (millions)**	**2015 Can $ (millions)**
Revenue				
Utility electricity sales and distribution	**$ 171.7**	$ 175.6	**$ 228.1**	$ 224.1
Less: cost of sales – electricity	**(90.0)**	(103.3)	**(119.8)**	(131.6)
Net Utility Sales - electricity	**81.7**	72.3	**108.3**	92.5
Utility natural gas sales and distribution	**276.8**	339.0	**371.4**	430.2
Less: cost of sales – natural gas	**(105.0)**	(172.0)	**(142.1)**	(217.3)
Net Utility Sales - natural gas	**171.8**	167.0	**229.3**	212.9
Utility water distribution & wastewater treatment sales and distribution	**137.4**	61.3	**181.7**	78.4
Less: cost of sales – water	**(9.2)**	—	**(12.2)**	—
Net Utility Sales - water distribution & wastewater treatment	**128.2**	61.3	**169.5**	78.4
Gas transportation	**25.7**	26.4	**34.3**	33.5
Other revenue	**11.0**	13.0	**14.6**	16.9
Net Utility Sales	**418.4**	340.0	**556.0**	434.2
Operating expenses	**(194.8)**	(167.3)	**(258.7)**	(214.1)
Other income	**3.9**	3.1	**5.1**	4.0
Divisional Operating Profit[1]	**$ 227.5**	$ 175.8	**$ 302.4**	$ 224.1

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

For the twelve months ended December 31, 2016, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $227.5 million as compared to U.S. $175.8 million for the comparable period in the prior year. Measured in Canadian dollars, the group's operating profit was $302.4 million as compared to $224.1 million during the same period in 2015, which represents an increase of $78.3 million or 35%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Twelve Months Ended December 31
Prior Period Operating Profit	**$ 224.1**
Existing Facilities	
Electricity: The CalPeco and Granite State Electric Systems generated operating profit consistent with the same period in the prior year.	(1.9)
Gas: Decrease primarily due to a one-time U.S. $3.0 million recoupment of revenue that occurred in the second quarter of 2015 at the EnergyNorth Gas System as permitted pursuant to its 2014 rate case, as well as lower demand at the gas systems due to warmer winter weather resulting in lower heating degree days. This was offset by lower operating costs due to prudent cost management.	(1.2)
Water: Increase primarily related to higher demand at the LPSCo and Bella Vista Water Systems, and lower operating expenses at the Pine Bluff Water System.	4.7
Other: Decrease primarily due to lower revenues for contracted services and the sale of the water heater rental business in the New England Gas System.	(3.0)
	(1.4)
New Facilities	
Water: The acquisition of the Park Water System closed on January 8, 2016.	45.5
	45.5
Rate Cases	
Electricity: Implementation of new rates at the CalPeco Electric System retroactive back to January 1, 2016 and interim rates at the Granite State Electric System.	12.7
Gas: Implementation of new rates at the Peach State and New England Gas Systems.	10.7
Water: Implementation of new rates at the Black Mountain Waste Water System along with the Bella Vista and Rio Rico Water Systems.	0.8
	24.2
Foreign Exchange	**10.0**
Current Period Divisional Operating Profit	**$ 302.4**

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Liberty Utilities 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.
Rio Rico Water/ Sewer System	Arizona	General Rate Case	$0.9	Application filed in October 2015 seeking a U.S. $0.9 million revenue increase. A final permanent rate decision issued in October 2016 allowed for a U.S. $0.98 million revenue increase effective November 2016.
Bella Vista Water System	Arizona	General Rate Case	$1.6	Application filed in October 2015 seeking a U.S. $1.6 million revenue increase. A final permanent rate decision issued in October 2016 allowed for a U.S. $0.96 million revenue increase effective November 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 filed in April 2016 and approved by the CPUC in December, 2016. The approved settlement authorized a U.S. $8.3 million margin revenue increase retroactive to Q1 2016.
Peach State Gas System	Georgia	GRAM	$0.6	Application filed in October 2016 seeking a U.S. $0.6 million revenue increase. A final permanent rate decision was issued in January 2017 approving a U.S. $0.7 million increase, with new rates effective February 2017.
Pending Rate Cases				
Entrada Del Oro	Arizona	General Rate Case	$0.3	Application filed in March 2016 seeking a U.S. $0.3 million revenue increase. A final permanent rate decision is expected in Q2 2017.
Granite State Electric System	New Hampshire	General Rate Case	$7.7	Application filed in April 2016 seeking a U.S. $7.7 million revenue increase. A temporary rate increase of U.S. $2.4 million became effective July 2016. A final permanent rate decision is expected in Q2 2017.
Illinois Gas System	Illinois	General Rate Case	$3.0	A settlement was filed with the Illinois Commerce Commission ("ICC") which results in the establishment of a decoupling mechanism, bad debt tracker, and enhanced growth mechanism. The settlement will result in annualized revenue increases of $2.3 million and is expected to be implemented in July 2017.
Iowa Gas System	Iowa	General Rate Case	$1.1	A settlement was filed with the Iowa Utilities Board ("IUB") in February 2017 which will result in an annualized revenue increase of U.S. $1.0 million, expected to become effective Q2 2017. A final permanent rate decision is expected in Q2 2017.
Woodmark/Tall Timbers Water & Wastewater Systems	Texas	General Rate Case	$2.0	Application filed in September 2016 seeking a U.S. $2.0 million revenue increase. A final permanent rate decision is expected in Q4 2017.

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 Georgia Rate Adjustment Mechanism ("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 Liberty's ownership and the first since 2009. The New England Gas System requested the increase in its general rates due to 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 occurred on March 1, 2016 and a further U.S. $0.5 million rate increase occurred 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 October 28, 2015, the Rio Rico Water and Wastewater System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, a 10.8% return on equity ("ROE") and 70% equity. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case sought to recover increased operating costs and capital improvements. The rate case also sought approval for the fair value Arizona rate evaluation model (“FARE”), a purchased power adjuster mechanism (“PPAM”) and a property tax adjuster mechanism (“PTAM”). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.98 million revenue increase. A Recommended Opinion and Order ("ROO") was issued in October 2016 accepting the settlement. A final decision was issued on November 21, 2016 approving the settlement, with implementation of new rates in November 2016. Its previous rate case was based on a test year ending February 2012.

On October 28, 2015, the Bella Vista Water System filed a rate case and financing application. The application sought an increase in revenue requirement of U.S. $1.6 million, or 33.6%, based on a test year ending December 31, 2014, a rate base of U.S. $13.2 million, 11.6% ROE, and 70% equity. This rate case seeks to recover increased operating costs and capital improvements. It also includes approval for the FARE, a PPAM and a PTAM. A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.96 million revenue increase. A ROO was issued in October 2016 accepting the settlement. A final decision was issued on November 21, 2016 approving the settlement, with implementation of new rates in November 2016. Its previous rate case was based on a test year ending March 2009.

On May 1, 2015, the CalPeco Electric System filed an application with the CPUC seeking an increase in revenue of U.S. $13.6 million (of which U.S. $11.4 million related to an increase in distribution margin revenue, and the remainder related to energy costs and other non-distribution charges), or 17.3%, based on a test year ending December 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The increase reflects a requested 10.5% ROE, and 55% equity. The previous test year ended December 31, 2011. In May 2016, an all-party settlement was filed with the CPUC allowing for a U.S. $9.8 million net distribution margin revenue increase, or approximately 86% of the requested increase. The increase reflects a 10.0% ROE and 52.5% equity. A final permanent rate decision from the CPUC was received in the fourth quarter of 2016, approving the settlement with a revision to the treatment of tax repairs in rates. This revision lowered the approved revenue increase to U.S. $8.3 million. The new permanent rates will be implemented January 2017, and will reflect retroactive effectiveness to the first quarter of 2016.

On October 1, 2016, the Georgia Gas System filed its annual GRAM. The application seeks a U.S. $0.6 million annual revenue increase to a proposed revenue requirement of U.S. $31.3 million, or a 1.9% increase, based on test year ending

June 2016. The GRAM proposals include a 10.5% ROE, 55.0% equity, and a U.S. $99.0 million rate base. PSC approval was received Q1 2017, allowing a U.S. $0.7 million increase, with implementation of new rates in February 2017.

Pending Rate Cases and Other Regulatory Applications

On March 3, 2016, the Entrada Del Oro Wastewater System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $0.3 million, or 90.5%, based on a test year ending October 31, 2015, a rate base of U.S. $2.2 million, 12% ROE, and 70% equity. Rates are proposed to be phased in over two years due to the magnitude of the increase. This rate case seeks to recover increased operating costs and capital improvements. An all-party settlement was filed with the ACC in Q1 2017, allowing a revenue increase of U.S. $0.2 million. A final decision and implementation of new rates is expected for the second quarter of 2017. Its previous rates became effective July 2006.

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

On July 25, 2016, the Illinois Gas System filed a rate application. The application seeks a U.S. $3.0 million annual revenue increase to a proposed revenue requirement of U.S. $15.3 million, or a 24% increase, based on a 2017 projected test year. Proposals include a 10.3% ROE, 54% equity, 4.83% cost of debt, 7.8% WACC, and a U.S. $45.0 million rate base. On February 17, 2017, a settlement was filed which calls for an annual revenue increase of $2.3 million, the establishment of a decoupling mechanism, a bad debt tracking mechanism, and a mechanism to enable further system expansion. A Final Order is expected in May 2017. Its previous rate case was filed in March 2014 and was based on a 2015 projected test year.

On July 25, 2016, the Iowa Gas System filed a rate application. The application seeks a U.S. $1.1 million annual revenue increase to a proposed revenue requirement of U.S. $3.2 million, or a 46% increase, based on a 2015 historical test year with pro-forma changes to June 2016. Proposals include a 10.25% ROE, 54% equity, 4.8% cost of debt, 7.76% WACC, and a U.S. $6.5 million rate base. Interim rates became effective August 4, 2016, allowing an interim revenue increase of U.S. $0.5 million on an annualized basis, or 50% of total proposed increase. On February 17, 2017, a settlement was filed which calls for an annual revenue increase of U.S. $1.0 million. A Final Order is expected in May 2017. Its previous rate case took place in 2001.

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

Park Water System Acquisition

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

Mountain Water Company is currently the subject of a condemnation lawsuit filed by the city of Missoula. Please see the "Regulatory Risk Section: *Condemnation Expropriation Proceedings"* for further discussion.

The Empire District Electric Company Acquisition

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

The final regulatory approval required for the acquisition from the Kansas Corporation Commission was received in December 2016 and the transaction closed on January 1, 2017.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in $ millions)	Three Months Ended December 31 2016	Three Months Ended December 31 2015	Twelve Months Ended December 31 2016	Twelve Months Ended December 31 2015
Corporate and other expenses:				
Administrative expenses	**$ 13.1**	$ 12.6	**$ 46.3**	$ 39.8
(Gain)/Loss on foreign exchange	**1.3**	0.3	**(0.4)**	(2.6)
Interest expense on convertible debentures and acquisition facility related to the acquisition of Empire	**18.2**	—	**57.6**	—
Interest expense	**20.5**	17.4	**74.0**	66.0
Interest, dividend, equity, and other income[1]	**(3.1)**	(2.0)	**(5.5)**	(4.0)
Other gains[2]	**(0.8)**	(1.0)	**(11.8)**	(2.2)
Acquisition-related costs	**2.4**	0.5	**12.0**	1.8
Gain on derivative financial instruments	**(12.9)**	—	**(15.8)**	(2.2)
Income tax expense	**11.5**	11.8	**37.1**	43.7

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

2 Includes Other Gains and loss/(gain) on long-lived assets per the Statement of Operations.

2016 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2016, administrative expenses totaled $13.1 million as compared to $12.6 million in the same period in 2015. The $0.5 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth.

For the three months ended December 31, 2016, interest expense on convertible debentures and acquisition financing totaled $18.2 million (see *Convertible Unsecured Subordinated Debentures and note 14 in the Audited Consolidated Financial Statements*). Convertible debentures, which are expected to convert to common shares upon closing of the Empire acquisition, were issued to finance the equity required for the transaction. Please see note 14 of the financial statements for further disclosure.

For the three months ended December 31, 2016, interest expense totaled $20.5 million as compared to $17.4 million in the same period in 2015. The interest expense for the period is a result of a U.S. $235.0 million Corporate Term Facility entered into in January 2016, and the assumed debt on the acquisition of the Park Water System.

For the three months ended December 31, 2016, other gains totaled a gain of $0.8 million as compared to a gain of $1.0 million in the same period in 2015. The decrease is primarily due to the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance during the same period in 2015.

For the three months ended December 31, 2016, gain on derivative financial instruments totaled $12.9 million as compared to nil in the same period in 2015. The increase was primarily driven by mark-to-market gains on foreign currency derivatives.

For the three months ended December 31, 2016, an income tax expense of $11.5 million was recorded as compared to an income tax expense of $11.8 million during the same period in 2015. The decrease in income tax expense is primarily due to the impact of additional interest expense on the convertible debentures offset by the impact of increased earnings from operations.

2016 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2016, administrative expenses totaled $46.3 million as compared to $39.8 million in the same period in 2015. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth and a stronger U.S. dollar. For the twelve months ended December 31, 2016, interest expense on convertible debentures and bridge financing totaled $57.6 million (see *Convertible Unsecured Subordinated Debentures and note 14 in the Audited Consolidated Financial Statements*).

For the twelve months ended December 31, 2016, interest expense totaled $74.0 million as compared to $66.0 million in the same period in 2015. The increase in interest expense for the period is a result of new indebtedness including: U.S. $160.0 million private placement issued in the second quarter of 2015, U.S. $235.0 million Corporate Term Facility entered into in January 2016, the assumed debt on the acquisition of the Park Water System, and repayments of the Shady Oaks Wind Facility senior debt in the second quarter of 2015. These items were partially offset by higher capitalized interest.

For the twelve months ended December 31, 2016, other gains totaled a gain of $11.8 million as compared to a gain of $2.2 million in the same period in 2015. The increase is primarily due to: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see note 18 in the financial statements) partially offset by (iii) the write-down of the Company's equity interest in the natural gas development projects which have been cancelled by the developer.

For the twelve months ended December 31, 2016, acquisition related costs totaled $12.0 million as compared to $1.8 million in the same period in 2015. The increase in costs are primarily due to $6.2 million due to the closing of the Park Water System, $1.3 million due to the Apple Valley Water System condemnation proceedings, and $3.1 million due to the Empire acquisition. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the twelve months ended December 31, 2016, the gain on derivative financial instruments totaled $15.8 million as compared to a gain of $2.2 million in the same period in 2015. The increase was due to mark-to market gains on foreign currency hedges offset by losses on the ineffective portion of derivative financial instruments accounted for as derivatives.

An income tax expense of $37.1 million was recorded in the twelve months ended December 31, 2016 as compared to an income tax expense of $43.7 million during the same period in 2015. The decrease in income tax expense for the twelve months ended December 31, 2016 is primarily due to decreased taxable earnings as a result of additional interest expense on the convertible debentures and a one-time non-cash charge of $2.7 million to deferred income taxes recorded during the twelve months ended December 31, 2015 as a result of an agreement reached with the Canada Revenue Agency (“CRA”) related to the Unit Exchange Transaction.

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.

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2016**	**2015**	**2016**	**2015**
Net earnings attributable to shareholders	**$ 46.3**	$ 38.0	**$ 130.9**	$ 117.5
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**(2.4)**	0.6	**1.9**	2.0
Equity loss from non-consolidated entities	**0.1**	—	**1.7**	—
Operating profit from non-consolidated entities	**1.5**	—	**3.9**	—
Loss from discontinued operations, net of tax	**—**	0.1	**—**	1.0
Income tax expense	**11.5**	11.8	**37.1**	43.7
Interest expense on convertible debentures and bridge financing	**18.2**	—	**57.6**	—
Interest expense	**20.5**	17.4	**74.0**	66.0
Other gains	**—**	(2.1)	**(8.6)**	(5.1)
(Gain)/loss on long-lived assets	**(0.8)**	1.1	**(3.3)**	2.9
Acquisition related costs	**2.4**	0.5	**12.0**	1.8
Gain on derivative financial instruments	**(12.9)**	—	**(15.8)**	(2.2)
Realized gain / (loss) on energy derivative contracts	**—**	—	**(1.0)**	0.6
(Gain) / loss on foreign exchange	**1.3**	0.3	**(0.4)**	(2.6)
Depreciation and amortization	**52.6**	41.9	**186.9**	149.8
Adjusted EBITDA	**$ 138.3**	$ 109.6	**$ 476.9**	$ 375.4

HLBV represents the value of net tax attributes earned by the Renewable Generation Group in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2016 amounted to $13.6 million and $41.0 million respectively.

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:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2016**	**2015**	**2016**	**2015**
Net earnings attributable to shareholders	**$ 46.3**	$ 38.0	**$ 130.9**	$ 117.5
Add (deduct):				
Loss from discontinued operations	**—**	0.1	**—**	1.8
Gain on derivative financial instruments	**(12.9)**	—	**(15.8)**	(2.2)
Realized gain / (loss) on derivative financial instruments	**—**	—	**(1.0)**	(0.9)
Loss (gain) on long-lived assets	**(0.8)**	1.1	**(3.3)**	2.9
Deferred tax expense due to an agreement with the CRA related to the Unit Exchange Transaction	**—**	—	**—**	2.7
(Gain) / Loss on foreign exchange	**1.3**	0.3	**(0.4)**	(2.6)
Interest expense on convertible debentures and bridge financing fees	**18.2**	—	**57.6**	—
Acquisition costs	**2.4**	0.5	**12.0**	1.8
Adjustment for taxes	**(3.1)**	(0.3)	**(18.4)**	0.5
Adjusted Net Earnings	**$ 51.4**	$ 39.7	**$ 161.6**	$ 121.5
Adjusted Net Earnings per share[1]	**$ 0.18**	$ 0.15	**$ 0.57**	$ 0.46

[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 December 31, 2016, Adjusted Net Earnings totaled $51.4 million as compared to Adjusted Net Earnings of $39.7 million, an increase of $11.7 million as compared to the same period in 2015. The increase in Adjusted Net Earnings for the three months ended December 31, 2016 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2015.

For the twelve months ended December 31, 2016, Adjusted Net Earnings totaled $161.6 million as compared to Adjusted Net Earnings of $121.5 million, an increase of $40.1 million as compared to the same period in 2015. The increase in Adjusted Net Earnings for the twelve months ended December 31, 2016 is primarily due increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2015.

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

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

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2016	2015	2016	2015
Cash flows from operating activities	**$ 121.3**	$ 94.3	**$ 287.3**	$ 261.9
Add (deduct):				
Changes in non-cash operating items	**(46.7)**	(17.7)	**(3.7)**	11.1
Cash used in discontinued operations	**—**	0.1	**—**	1.8
Production based cash contributions from non-controlling interests	**—**	—	**9.5**	10.8
Interest expense on convertible debentures and bridge financing fees	**18.2**	—	**57.6**	—
Acquisition costs	**2.4**	0.5	**12.0**	1.8
Cash generated from sale of long-lived assets	**—**	—	**(8.6)**	—
Cash generated from non-consolidated entities	**0.6**	—	**1.7**	—
Adjusted Funds from Operations	**$ 95.8**	$ 77.2	**$ 355.8**	$ 287.4

For the three months ended December 31, 2016, Adjusted Funds from Operations totaled $95.8 million as compared to Adjusted Funds from Operations of $77.2 million, an increase of $18.6 million as compared to the same period in 2015.

For the twelve months ended December 31, 2016, Adjusted Funds from Operations totaled $355.8 million as compared to Adjusted Funds from Operations of $287.4 million, an increase of $68.4 million as compared to the same period in 2015.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES [1]

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2016	2015	2016	2015
Renewable Generation Group:				
Maintenance	**$ 21.0**	$ 11.2	**$ 58.6**	$ 27.4
Investment in Capital Projects[1]	**169.0**	43.9	**538.1**	178.7
	$ 190.0	$ 55.1	**$ 596.7**	$ 206.1
Liberty Utilities Group:				
Rate Base Maintenance	**$ 27.0**	$ 25.1	**$ 102.7**	$ 82.5
Rate Base Growth	**96.0**	5.4	**133.7**	30.5
	123.0	30.5	**236.4**	113.0
Corporate	**5.0**	8.3	**29.7**	31.2
Total Capital Expenditures	**$ 318.0**	$ 93.9	**$ 862.8**	$ 350.3

1 Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that were jointly developed by the company.

2016 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2016, the Renewable Generation Group incurred capital expenditures of $190.0 million as compared to $55.1 million during the same period in 2015. At the end of 2016, the Renewable Generation Group purchased approximately $75 million of turbine components ("Safe Harbor Turbines") that will qualify between 500 MW and 700 MW of new projects for 100% of the production tax credit ("PTC"). The full PTC is approximately U.S. $23 per MWh and subject to an annual adjustment for inflation. The PTC at the full rate is available to projects in the United States completed before the end of 2020 if they commenced construction prior to December 31, 2016 or have purchased components that qualify under the IRS safe harbor rules ("Full PTC Projects"). Projects other than Full PTC Projects will receive 80% of the applicable PTC rate if construction commences in 2017, 60% if construction commences in 2018, and 40% if construction commences in 2019. Securing access to the full PTC rate is an important competitive advantage in the U.S. market. The Renewable Generation Group is currently evaluating projects to maximize the value of this equipment.

The remaining capital expenditures primarily relate to construction at the Donnacona Hydro Facility and the Bakersfield II Solar Project, as well as development spending at the Great Bay Solar, the Chaplin-Blue Hill and Amherst Island Wind Projects. The prior year investment was related to completion of the Bakersfield II Solar Facilities in addition to continued development of the Great Bay Solar and Amherst Island Wind Projects.

During the three months ended December 31, 2016, the Liberty Utilities Group invested $123.0 million in capital expenditures as compared to $30.5 million during the same period in 2015. The Liberty Utilities Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems. Specific projects that the capital expenditures relate to include partial financing of the Luning Solar project located in Mineral County, Nevada.

Corporate spending includes transmission operations spend on the Phase I of the North Lake Take System upgrade. Phase I involves the upgrading the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2016 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2016, the Renewable Generation Group incurred capital expenditures of $596.7 million as compared to $206.1 million during the same period in 2015. At the end of 2016, the Renewable Generation Group purchased approximately $75 million of Safe Harbor Turbines. During the year, the Renewable Generation Group incurred $343.9 million as a result of the acquisition of the Odell Wind Project. Of the total cost, $236.1 million was received from Tax Equity Investors. Throughout the year, the Renewable Generation Group continued construction of the Bakersfield II Solar Project as well as advanced development of its Great Bay Solar, Amherst Island Wind and Chaplin-Blue Hill Wind projects.

During the twelve months ended December 31, 2016, the Liberty Utilities Group invested $236.4 million in capital expenditures as compared to $113.0 million during the same period in 2015. The Liberty Utilities Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems. Specific projects that the capital expenditures relate to include partial financing of the Luning Solar project located in Mineral County, Nevada.

Corporate spending includes transmission operations spend on the Phase I of the North Lake Take System upgrade. Phase I involves the upgrading the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2017 Capital Investments

In 2017, the company plans to spend between $1.1 billion and $1.3 billion on capital investment opportunities. Actual expenditures during the course of 2017 may vary due to timing on various project investments and the realized U.S. dollar exchange rate.

Expected 2017 capital investment ranges are as follows:

(all dollar amounts in $ millions)			
Renewable Generation Group:			
Maintenance	$ 40.0	-	$ 50.0
Investment in Capital Projects	500.0	-	580.0
Total Renewable Generation Group:	$ 540.0	-	$ 630.0
Liberty Utilities Group:			
Rate Base Maintenance	$ 160.0	-	$ 170.0
Rate Base Growth	400.0	-	500.0
Total Liberty Utilities Group:	$ 560.0	-	$ 670.0
Total 2017 Capital Investments	**$ 1,100.0**	**-**	**$ 1,300.0**

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 2017 capital investments.

LIQUIDITY AND CAPITAL RESERVES

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

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at December 31, 2016:

	As at December 31, 2016				As at Dec 31, 2015
(all dollar amounts in $ millions)	Corporate	Generation	Utilities	Total	Total
Committed facilities	$ 65.0	$ 440.3	$ 268.5	**$ 773.8**	$ 783.3
Funds drawn on facilities	—	(242.9)	—	**(242.9)**	(27.3)
Letters of credit issued	(12.1)	(180.9)	(41.9)	**(234.9)**	(164.4)
Liquidity available under the facilities	**52.9**	**16.5**	**226.6**	**296.0**	591.6
Cash on hand				**110.4**	124.8
Total Liquidity and Capital Reserves	**$ 52.9**	**$ 16.5**	**$ 226.6**	**$ 406.4**	$ 716.4

As at December 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. The facility matures on November 19, 2017 and is subject to customary covenants.

As at December 31, 2016, the Renewable Generation Group's facilities consisted of a $350.0 million Generation Credit Facility and $90.3 million Generation Letter of Credit Facility (Cdn $50.0 million and U.S. $30.0 million). As at December 31, 2016, the group had drawn $242.9 million and had $180.9 million in outstanding letters of credit. The facilities mature on July 31, 2019 and October 30, 2016, respectively, and are subject to customary covenants. Subsequent to quarter end, the Company extended the maturity of the Generation Letter of Credit Facility to October 31, 2017.

As at December 31, 2016, the Liberty Utilities Group's $268.5 million (U.S. $200.0 million) senior unsecured revolving credit facility ("Liberty Credit Facility") was undrawn and had $41.9 million (U.S. $31.2 million) of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants.

As part of the Park Water System's acquisition on January 8, 2016, the Company assumed U.S. $22.5 million of debt outstanding under a non-revolving term credit facility. 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.

On February 9, 2016, in connection with the acquisition of Empire, the Company obtained U.S. $1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. Upon receiving the initial instalment from the Debentures (described below), the Company reduced the commitments under the Acquisition Facility by U.S. $263.6 million. On December 30, 2016 the Company drew U.S. $1,336.4 million on the Acquisition Facility. The funds drawn were transferred to a paying agent for purposes of distribution to holders of the common shares of Empire (see note 3(a) on the Company's Audited Consolidated Financial Statements) on January 1, 2017. The Acquisition Facility matures on December 29, 2017 and is subject to an initial funding fee payment on March 30, 2017 calculated on the balance drawn on the that date. The Acquisition Facility is subject to margin step ups and duration fees that commence on March 30, 2017 and are calculated based on the amounts drawn.

Subsequent to year end, on February 7, 2017, upon receipt of the Final Instalment from the Debentures, the Company repaid U.S. $567.6 million under the Acquisition Facility. The remaining funds drawn are expected to be repaid on March 24, 2017 from proceeds received from the Liberty Private Placement discussed below and general corporate funds.

Long Term Debt

On January 4, 2016 a subsidiary of the Company entered into a U.S. $235.0 million term credit facility with two U.S. banks ("Corporate Term Facility"). 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, 2018, and is subject to customary covenants.

Subsequent to year end, on January 17, 2017 the Renewable Generation Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Renewable Generation Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars for an effective yield of 4.86%.

Subsequent to year end, on March 1, 2017, the Liberty Utilities Group entered into a Note Purchase Agreement for the issuance of U.S. $750.0 million of senior unsecured notes ("Liberty Private Placement") with 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, Liberty Utilities had entered into forward contracts to lock in the underlying U.S. Treasury interest rates (see "Interest Rate Risk section"). Considering the effect of the hedges, the effective weighted average rate paid by Liberty Utilities is 3.6%. The closing of the offering is scheduled to occur on March 24, 2017, with the proceeds to be applied to repay the balance of the Acquisition Facility and other existing indebtedness.

As at December 31, 2016, the weighted average tenure of APUC's total long term debt is approximately 9.1 years with an average interest rate of 4.9%.

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

Convertible Unsecured Subordinated Debentures

On March 1, 2016, in connection with the acquisition of Empire, the Company completed the sale of $1.0 billion aggregate principal amount of 5.0% convertible debentures ("Debentures"). On March 9, 2016, the underwriters exercised their option to purchase $150 million additional debentures, bringing the total amount of the offering to $1.15 billion.

The convertible debentures were sold on an instalment basis at a price of $1,000 principal amount debenture, of which $333 was received on closing of the debenture offering and the remaining $667 (the "Final Instalment") is receivable on a date ("Final Instalment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial instalment were approximately $383.0 million.

The convertible debentures mature on March 31, 2026 and bear interest at an annual rate of 5% per $1,000 dollars principal amount of convertible debentures until and including the Final Instalment Date, and bears an interest rate of 0% thereafter.

The Final Instalment Date took place, subsequent to year-end, on February 2, 2017. The proceeds received from the Final instalment were $767.1 million. As the Final Instalment Date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017.

APUC will issue up to 108,490,556 common shares on conversion of all debentures. As at March 1, 2017, a total of 107,517,895 common shares of the company were issued, representing conversion into common shares of 99.1% of the convertible debentures. After the Final Instalment 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 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.

Credit Ratings

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

Subsequent to year end, on February 6, 2017, following the announcement that APUC had received the Final Instalment proceeds from the Debentures, S&P revised the outlook on APUC's consolidated corporate credit rating from negative to stable. S&P had placed APUC's consolidated credit rating on negative watch on February 9, 2016, pending the completion of the Empire acquisition and the execution on the financing plan, including the receipt of the Final Instalment and conversion of the Debentures to common shares of the Company. S&P's reiteration of the outlook reflects their assessment of APUC's stable cash flows from its regulated utilities and contracted unregulated power business, along with its commitment to a balance between debt and equity to fund its acquisition and development activities such that its funds from operations-to-debt ratio remains in the 14%-15% range.

Subsequent to year end, on February 13, 2017, following the announcement that APUC had received the Final Instalment proceeds from the Debentures, DBRS removed the "Under Review with Developing Implications" status from the ratings of APUC and its subsidiaries. DBRS had placed APUC's ratings as "Under Review with Developing Implications" on February 10, 2016 pending completion of the acquisition and execution of the financing plan, including the receipt of the Final Instalment proceeds. DBRS reiterated their view that the acquisition of Empire will have a positive impact on APUC's and Liberty Finance's business risk assessment. The impact on their financial risk assessment was cited as modestly negative, with the overall impact on the ratings as neutral. DBRS also reiterated that the rating actions for APCo reflect their view that the acquisition of Empire has no impact on the business or financial risk assessments of APCo.

Contractual Obligations

Information concerning contractual obligations as of December 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]	**$ 3,901.3**	$ 1,871.9	$ 745.3	$ 304.9	$ 979.2
Convertible debentures	**358.6**	—	—	—	358.6
Advances in aid of construction	**105.2**	3.1	—	—	102.1
Interest on long-term debt obligations	**806.2**	194.8	153.0	110.7	347.7
Purchase obligations	**398.9**	398.9	—	—	—
Environmental obligations	**76.8**	4.0	23.9	7.1	41.8
Derivative financial instruments:					
Cross currency swap	**95.4**	4.1	7.7	49.4	34.2
Interest rate swap	**13.4**	—	13.4	—	—
Purchased power	**214.9**	63.3	74.0	77.6	—
Gas delivery, service and supply agreements	**258.4**	62.2	82.9	49.0	64.3
Service agreements	**721.1**	41.4	84.8	91.2	503.7
Capital projects	**86.4**	66.7	19.6	0.1	—
Operating leases	**157.2**	7.3	13.4	12.9	123.6
Other obligations	**79.8**	32.6	—	—	47.2
Total Obligations	**$ 7,273.6**	**$ 2,750.3**	**$ 1,218.0**	**$ 702.9**	**$ 2,602.4**

[1] Exclusive of deferred financing costs, bond premium/discount, fair value adjustments at the time of issuance or acquisition.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2016, APUC had 274,087,018 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, 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 5.00% convertible unsecured subordinated debentures of APUC. 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 and the remaining $667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of APUC's acquisition of Empire. On the Final Instalment Date each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

The Final Instalment Date was established as February 2, 2017, at which time APUC received the Final Instalment payment and concurrently issued 98,022,082 of its common shares as a result of the conversion of $1,039.0 million of debentures to equity. The net proceeds from the Final Instalment of $744.1 million were used to repay a portion of APUC's Acquisition Facility. Subsequent to the Final Instalment Date, an additional 9,495,813 common shares were issued as a result of an additional $100.7 million debentures converting to equity. As of March 1, 2017, $10.3 million of convertible debentures remain outstanding bearing an interest rate of 0%.

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 December 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 common shares of APUC. As at December 31, 2016, 61,419,484 common shares representing approximately 22% of total common shares outstanding had been registered with the Reinvestment Plan. During the quarter ended December 31, 2016, 725,171 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 13, 2017, an additional 823,738 common shares were issued under the Reinvestment Plan.

SHARE BASED COMPENSATION PLANS

For the twelve months ended December 31, 2016, APUC recorded $5.7 million in total share-based compensation expense as compared to $5.3 million for the same period in 2015. There is no tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the audited consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2016, total unrecognized compensation costs related to non-vested options and share unit awards were $3.2 million and $2.2 million, respectively, and are expected to be recognized over a period of 1.77 and 1.74 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 twelve months ended December 31, 2016, the Company granted 2,596,025 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $10.85, 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 December 31, 2016, a total of 6,045,014 options are issued and outstanding under the plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. During the twelve months ended December 31, 2016, the Company granted (including dividends) 219,315 PSUs to executives and employees of the Company. During the year the Company settled 181,875 PSUs by issuing 91,280 shares from treasury, with the balance withheld as payment in lieu of minimum tax withholdings.

As at December 31, 2016, a total of 578,988 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2016, the Company issued 67,192 DSUs to the directors of the Company.

As at December 31, 2016, a total of 224,663 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 twelve months ended December 31, 2016, the Company issued 144,264 common shares to employees under the ESPP.

As at December 31, 2016, a total of 496,030 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels at its individual operating groups and at an overall company level.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have appropriately sized revolving credit facilities available for ongoing investment in growth and development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Emera Inc.

A member of the Board of APUC is an executive at Emera. During 2016, the Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro subsidiaries of Emera, amounting to U.S. $10.2 million as compared to U.S. $6.7 million during the same period in 2015. During 2016, Liberty Utilities purchased natural gas amounting to U.S. $3.9 million as compared to U.S. $2.3 million during the same period in 2015 from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction. On May 13, 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The total cost of the contract is estimated at $8.8 million and is expected to be completed in 2017. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $0.7 million to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $0.8 million included in accruals in 2016 as compared to U.S. $0.5 million during the same period in 2015, related to these transactions at the end of the year.

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 $3.3 million as compared to $2.0 million during the same period in 2015.

Trafalgar

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

In 2003 and 2004, the Company reimbursed the Related Entity $1.0 million of the approximately $2.0 million in third-party legal fees it had initially funded and APUC agreed to fund future legal fees and other liabilities. It was agreed that any net proceeds from the litigation and bankruptcy proceedings would be shared proportionally to the quantum of net legal costs funded by each party.

On June 30, 2016, the Company received U.S. $10.1 million in proceeds from the settlement of this matter and, subsequent to quarter-end, paid U.S. $2.9 million to the Related Entity as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in the second quarter of 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2017.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

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.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by APUC's internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops as well as APUC's "Risk Insights" program which provides all employees with a mechanism to communicate risks and opportunities at any time. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and presented to the Board of Directors' Risk Committee. The key risk categories assessed include: safety, environment, natural disasters, compliance, security (physical and cyber), financial reporting, operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

Risks are assessed consistently across the organization using a common risk scoring matrix to assess impact and likelihood. Financial, reputation, and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of APUC's strategic and business plans.

The development and execution of risk treatment plans for the organization's top risks are actively monitored by the Executive team. APUC's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and reported to the Audit Committee of the Board. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, the Executive team, and the Board of Directors for consideration.

APUC's ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust and that APUC's risk appetite is thoroughly considered in decision-making across the organization.

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Treasury Risk Management

Foreign Currency Risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 84% of EBITDA in 2016 and 83% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $40.0 million ($0.16 per share) on an annual basis.In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs.

Although APUC may enter into derivative contracts to hedge currency exchange rate exposure, the Company typically does not hedge its full exposure. To the extent that the Company does enter into currency hedges, the Company will not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts

The $1.15 billion of convertible debentures raised in the first quarter of 2016 to fund the acquisition of Empire were denominated in Canadian dollars. In order to mitigate the effects of a potential funding mismatch due to fluctuations in the foreign exchange rate, over the course of 2016 the Company converted the total expected proceeds into U.S. dollars by purchasing spot and forward currency exchange contracts with an average U.S. exchange rate of approximately $1.3282. Hedge accounting was not applicable, hence changes in value of the forward contracts have been recorded in the Company's Statement of Operations.

Market Price Risk

The Renewable 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 Renewable 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 Renewable 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 Renewable 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 Renewable Generation Group entered into a financial hedge, which expired December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge was structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool’s current spot market rates. Starting in 2017, the unhedged production based on long term projected averages is approximately 65,000 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. $0.7 million on an annualized basis.

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

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility’s expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility’s expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 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 Renewable 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 December 31, 2016, the Renewable Generation Group had not entered into any such short-term derivative contracts.

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

Credit/Counterparty Risk

APUC and its subsidiaries through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Company.

Approximately 94% of the Renewable Generation Group's revenues are earned from large utility customers having a credit rating of Baa1 or better by Moody's Rating Services, or BBB or higher by S&P Rating Services, or BBB or higher by DBRS. The following chart sets out the Renewable Generation Group's customers representing greater than 5% of total revenues and their credit ratings and percentage of total revenue associated with the customer:

Counterparty	Credit Rating [1]		Approximate Annual Revenues	Percent of Revenue
PJM Interconnection LLC	Aa2	$	32.2	13.2%
Ontario Electricity Financial Corporation	Aa2		29.7	12.2%
Manitoba Hydro	A		28.7	11.8%
Hydro Quebec	Aa2		27.5	11.3%
Commonwealth Edison	Baa1		25.0	10.3%
Pacific Gas and Electric Company	A3		22.6	9.3%
Electric Reliability Council of Texas (ERCOT)	Aa3		17.4	7.2%
Connecticut Light and Power	Baa1		14.3	5.9%
Total		**$**	**197.4**	

[1] Ratings by Moody's , Standard & Poor's, or DBRS.

The remaining revenue of the company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $16.1 million which is spread over approximately 178,000 connections, resulting in an average outstanding balance of approximately $90 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $46.8 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $21.1 million. The natural gas and electrical utilities both derive over 86% of their revenue from residential customers.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Company. Losses from a utility customer may not be fully compensated through bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement with the Renewable Generation Group is unable to perform, the Renewable Generation Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

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 December 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 $242.9 million outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $2.4 million annually;
- The Liberty Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Acquisition Facility is subject to a variable interest rate and had $1,794.4 million (U.S. $1,336.4 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $17.9 million annually;
- The Corporate Term Facility is subject to a variable interest rate and had $315.5 million (U.S. $235.0 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $3.2 million annually;
- The Park Water System term credit facility is subject to a variable interest rate and had $30.2 million (U.S. $22.5 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually; and
- To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings.
    - In the fourth quarter of 2014, the Renewable Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.
    - On October 25, 2016, the Company entered into forward contracts to purchase U.S. $250.0 million 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250.0 million 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500.0 million bonds in relation to the acquisition of Empire (note 3(a)). Subsequent to year-end, the Company entered into a note purchase agreement to issue U.S. $750 million of notes with a weighted average coupon of 4.0% based on pricing established on January 27, 2017 (note 9(c)). Concurrent with the pricing of the notes, the Company also settled the open forward contracts on January 27, 2017, resulting in an effective interest rate on the bond offering of approximately 3.6%. Hedge accounting will apply to the effective portion of the realized gain on the hedge, while the ineffective portion of approximately U.S. $0.6 million will be recorded in income in the first quarter of 2017.

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

APUC is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which we do business could adversely affect APUC's results from operations, our return to shareholders, and cash flow. The Company endeavors to take tax positions that are sustainable, however, there can be no assurance that the tax positions taken by the Company will not be subject to challenge by the Canada Revenue Agency ('CRA") or the IRS. A successful challenge by either agency could impact our return to shareholders.

There is the potential for changes to the U.S. tax code (Internal Revenue Code or "IRC"). It is not possible to know what change to the IRC, if any, will be enacted in the U.S., and therefore, it is not possible to know what effect the changes, if any, might have on the Company. There can be no assurance that any changes to the U.S. IRC would not impact the Company's tax-related assets, liabilities, and expense which could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Development by the Renewable Generation Group of renewable power generation facilities in the United States is dependent in part on federal tax credits and other tax incentives, the availability of which requires that construction of the applicable facility be commenced by a statutory deadline. While these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down in the amount of the incentives. There can be no assurance that reduced incentive levels will be sufficient to support continued development and construction of renewable power facilities in the United States, nor that the applicable legislation will not be further limited. In addition, the Renewable Generation Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

Liquidity Financing Risk

As of December 31, 2016, the Company had approximately $4,272.0 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

The ability of the Company to raise additional debt or equity or to do so on favorable terms may be affected by the Company's financial and operational performance, and by financial market disruptions or other factors outside the control of the Company.

In addition, the Company may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the degree of the Company's leverage could, among other things, limit the Company's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Company's flexibility and discretion to operate its business; limit the Company's ability to declare dividends on its Common Shares; require the Company to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Company's existing credit ratings; expose the Company to increased interest expense on borrowings at variable rates; limit the Company's ability to adjust to changing market conditions; place the Company at a competitive disadvantage compared to its competitors that have less debt; make the Company vulnerable to any downturn in general economic conditions; and render the Company unable to make expenditures that are important to its future growth strategies.

The Company will need to refinance or reimburse amounts outstanding under the Company's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favorable than the current terms, the ability of the Company to declare dividends may be adversely affected.

The ability of the Company to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Company, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and future capital expenditure requirements. In addition, the ability of the Company to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Company and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Company would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("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. Empire has a BBB rating from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long term debt securities issued. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

Commodity Price Risk

The Renewable Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.

- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 164,000 MW-hrs in fiscal 2017, of which 133,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 25,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 164,000 MW-hrs. The risk associated with the expected market purchases of 25,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 78% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $83 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.1 million on an annualized basis.

The CalPeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. The CalPeco Electric System also benefits from a revenue decoupling mechanism and a vegetation management memorandum account. The revenue decoupling mechanism decouples base revenues from fluctuations caused by weather and economic factors reducing volumetric risk for the utility. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility, reducing the potential for expenses to exceed the amounts allowed for in general rates.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the New Hampshire Public Utilities Commission ("NHPUC") on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia PSC for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 54% of its 2016 generation fuel supply need through coal. Approximately 97% of its 2016 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts satisfy approximately 92% of anticipated fuel requirements for 2017 and 23% for 2018 for the Asbury Coal Facility. In order to manage exposure to fuel prices, future coal supplies will be acquired using a combination of short-term and long-term contracts.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel accommodation clause and PGA filings and are embedded in the approved rates in such filings.

OPERATIONAL RISK MANAGEMENT

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Renewable Generation Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Liberty Utilities Group regularly works with its governing authorities to manage the affairs of the business, employing both local, state level, and corporate resources.

Condemnation Expropriation Proceedings

The Liberty Utilities Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require fair compensation to be paid. Determination of such fair compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value.

On January 8, 2016, the Company announced it had acquired Western Water Holdings LLC, which is the parent company of the regulated water distribution utility Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("Liberty Park Water"). Liberty Park Water owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and parts of western Montana. Mountain Water Company is the water utility in western Montana serving customers in and around the municipality of Missoula. Liberty Utilities (Apple Valley Ranchos Water) Corp. ("Liberty Apple Valley"). formerly known as Apple Valley Ranchos Water Co., is the water utility serving customers in and around the town of Apple Valley, California.

Mountain Water is currently the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula can proceed with condemnation of Mountain Water's assets. Upon taking possession of Mountain Water's assets, the compensation to be paid by the city of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. $88.6 million as of May 6, 2014). Mountain Water is expected to receive certain additional amounts that may include legal fees, interest, post-valuation capital expenditures and property tax reimbursement.

On December 22, 2015, various developers filed a lawsuit in Missoula County District Court against Mountain Water and the city of Missoula. The lawsuit pertains to Funded By Other (FBO) contracts between each developer and Mountain Water. Under these FBO contracts, the developers paid for facilities to provide water service and Mountain Water agreed to refund such amounts over a 40 year period. As of the date of acquisition of Western Water Holdings, the outstanding balance of these advances, on a non-discounted basis, was U.S. $23.1 million. On February 21, 2017, the court issued an order imposing equitable liens on the Mountain Water assets that are the subject of the FBO contracts, mandating that the liens be satisfied directly from the condemnation award, if and when paid.

APUC expects that, in light of the foregoing and agreements entered in to at the time of the acquisition, the net amount to be recognized by APUC in connection with the conclusion of all such proceedings is reasonably likely to be at least $103 million. However, such amount remains uncertain in light of outstanding legal issues and proceedings and, as a result, no assurances can be given as to such amount.

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the assets of Liberty Apple Valley. Liberty Apple Valley filed a response to the condemnation complaint on February 23, 2016. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases; initially to determine the necessity of the taking, and then, if the Town of Apple Valley is successful in the right to take proceeding, a second phase is held to determine the fair market value of the assets to be taken. The matter is expected to take two to three years to resolve. The condemnation action could have potential adverse financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Liberty Apple Valley's assets by a jury if so elected by either party, along with a determination of interest and attorney's fees by the court.

Cycles and Seasonality

Renewable Generation Group

The Renewable Generation Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies, impacting the amount of power that can be generated in a year.

The Renewable Generation Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the spring and fall periods, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Renewable Generation Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Liberty Utilities Group

The Liberty Utilities Group's demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Liberty Utilities Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

Development and Construction Risk

The Company actively engages in the development and construction of new power generation facilities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Company's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

The Company mitigates these risks through its due diligence processes, sound project management practices and appropriate contingency plans and reserves.

Risks Specific to Renewable Generation Projects:

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Company relies on financing from third party tax equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

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 the Company and various affiliates in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Company and various affiliates 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 ("Trafalgar Hydro Facilities"). Over the past 16 years, there have been various District Court adversary proceedings and bankruptcy proceedings in connection with this matter.

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

In June, 2016, all of the above legal proceedings were settled pursuant to the terms outlined in the United States Bankruptcy Court for the Northern District of New York Order Approving Terms of Settlement which was entered into Bankruptcy Court on June 20, 2016. Pursuant to the Global Settlement, U.S. Bank was allowed U.S. $1.5 million. The Company and various affiliates were awarded approximately U.S. $10.1 million, amounts of which were received on June 30, 2016 (the "Litigation Proceeds"). The Litigation Proceeds were dispersed as more particularly outlined in MDA for the nine month period ending September 30, 2016 - Related Party Transactions.

Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corp., 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 GA as a price escalator. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011 onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court's judgment of March 12, 2015. The appeal was heard on December 14 and December 15, 2015. The Ontario Court of Appeal dismissed the OEFC's appeal by judgment dated April 19, 2016. OEFC sought leave to appeal to the Supreme Court of Canada (the "SCC"). In addition, OEFC brought a motion to stay the payment of the retroactive payments pending its appeal to the SCC. On August 5, 2016, the Court of Appeal denied OEFC's motion for a stay. On September 13, 2016, the Ontario Court of Appeal dismissed the motion brought by the OEFC to set aside or vary the order. On October 21, 2016, the OEFC made retroactive payments of $5.1 million and $0.3 million of interest to Long Sault. On January 19, 2017, the SCC denied OEFC's application for leave to appeal.

Côte Ste-Catherine Water Lease Dues

In October 2011, the Québec Court of Appeal ordered Mont-Laurier Partnership, a subsidiary of the Company, to pay approximately $5.4 million (including interest) to the Government of Québec 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 of the Company believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6.9 million. In 2012, a subsidiary of the Company paid $1.9 million to the Government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interest on any amount ultimately determined to be payable or recoverable. The parties continue to engage in settlement discussions with a view to resolving this matter.

QUARTERLY FINANCIAL INFORMATION

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

(all dollar amounts in $ millions except per share information)	1st Quarter 2016	2nd Quarter 2016	3rd Quarter 2016	4th Quarter 2016
Revenue	$ 341.7	$ 222.8	$ 221.3	$ 310.2
Net earnings / (loss) attributable to shareholders from continuing operations	42.0	24.8	17.7	46.3
Net earnings / (loss) attributable to shareholders	42.0	24.8	17.7	46.3
Net earnings / (loss) per share from continuing operations	0.15	0.08	0.06	0.16
Net earnings / (loss) per share	0.15	0.08	0.06	0.16
Adjusted Net Earnings	56.1	30.9	26.6	51.4
Adjusted Net Earnings per share	0.21	0.11	0.09	0.18
Adjusted EBITDA	147.9	99.2	91.4	138.3
Total assets	5,615.5	5,555.0	6,020.8	8,249.5
Long term debt[1]	2,214.5	2,199.9	2,380.8	4,272.0
Dividend declared per common share	$ 0.13	$ 0.14	$ 0.14	$ 0.14
	1st Quarter 2015	**2nd Quarter 2015**	**3rd Quarter 2015**	**4th Quarter 2015**
Revenue	$ 381.9	$ 196.2	$ 189.6	$ 260.3
Net earnings / (loss) attributable to shareholders from continuing operations	43.1	20.6	16.7	38.1
Net earnings/(loss) attributable to shareholders	43.1	19.9	16.5	38.0
Net earnings / (loss) per share from continuing operations	0.16	0.07	0.06	0.14
Net earnings/(loss) per share	0.16	0.07	0.05	0.14
Adjusted Net Earnings	42.6	22.2	17.3	39.7
Adjusted Net Earnings per share	0.17	0.08	0.06	0.15
Adjusted EBITDA	114.5	81.1	70.2	109.6
Total assets	4,531.4	4,396.5	4,759.0	4,991.7
Long term debt[1]	1,482.7	1,440.3	1,613.3	1,486.8
Dividend declared per common share	$ 0.11	$ 0.12	$ 0.13	$ 0.13

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

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

Quarterly revenues have fluctuated between $189.6 million and $381.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, 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 $16.5 million and net earnings of $46.3 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 December 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 December 31, 2016, APUC's disclosure controls and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

During the year ended December 31, 2016, APUC acquired the Park Water Facility. The financial information for this acquisition is included in this MD&A and in note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded this acquisition from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2016 due to the complexity associated with assessing internal controls during integration efforts.

For the twelve months ended December 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. APUC continues to implement its internal control structure over the operations of the acquired business discussed above.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2016 based on the criteria set forth in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2016.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its audited consolidated 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.

APUC's significant accounting policies and new accounting standards are discussed in notes 1 and 2 to the consolidated financial statements, respectively. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated Useful Lives and Recoverability of Long-Lived Assets, Intangibles and Goodwill

The Company makes judgments a) to determine the recoverability of a development project, and the period over which the costs are capitalized during the development and construction of the project, b) to assess the nature of the costs to be capitalized, c) to distinguish individual components and major overhauls, and d) to determine the useful lives or unit-of-production over which assets are depreciated.

Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process.

The carrying value of long-lived assets, including intangible assets and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill. Some of the factors APUC considers as indicators of impairment include a significant change in operational or financial performance, unexpected outcome from rate orders, natural disasters, energy pricing and changes in regulation. When such events or circumstances are present, the Company assesses whether the carrying value will be recovered through the expected future cash flows. If the facility includes goodwill, the fair value of the facility is compared to its carrying value. Both methodologies are sensitive to the forecasted cash flows and in particular energy prices, long-term growth rate and, discount rate for the fair value calculation.

A recoverability analysis was performed in 2016 for wind and hydro generating assets operating without a PPA and in 2015 for certain small hydro generating facilities. No impairment provision was required in 2016 (2015 - $1.1 million). A quantitative assessment of goodwill performed as at September 30, 2014 concluded that the fair value of each reporting unit substantially exceeded their carrying value. In 2016 and 2015, Management performed a qualitative assessment for each of the eleven reporting units that were allocated goodwill. No goodwill impairment provision was required.

Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Liberty Utilities Group's operations.

Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets obtained from external parties adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2016) recently released by the Society of Actuaries adjusted to reflect the 2016 Social Security Administration ultimate improvement rates.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2016 are outlined in the following table. They are calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and method used to prepare the sensitivity analysis has not changed from previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized in the consolidated financial statements.

	2016 Pension Plans		2016 OPEB Plans	
(all dollar amounts in $ millions)	Accrued Benefit Obligation	Net Periodic Pension Cost	Accumulated Postretirement Benefit Obligation	Net Periodic Postretirement Benefit Cost
Discount Rate				
1% increase	(32.8)	(1.6)	(10.2)	(0.9)
1% decrease	40.0	2.7	12.8	0.8
Future compensation rate				
1% increase	0.2	0.9	—	—
1% decrease	(0.2)	(1.2)	—	—
Expected return on plan assets				
1% increase	—	(2.1)	—	(0.2)
1% decrease	—	2.1	—	0.2
Life expectancy				
1% increase	20.9	2.6	7.3	0.8
1% decrease	(22.4)	(2.6)	(6.9)	(1.0)
Health care trend				
1% increase	—	—	11.3	1.5
1% decrease	—	—	(9.4)	(1.4)

Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions generally included in a present value calculation of the related cash flows.

Acquired assets and liabilities assumed that are subject to critical estimates include regulated property, plant and equipment, regulatory assets and liabilities, long-term debt and pension and OPEB obligations. The fair value of regulated property, plant and equipment is assessed using an income approach where the estimated cash flows of the assets are calculated using the approved tariff and discounted at the approved rate of return. The fair value of regulatory assets and liabilities considers the estimated timing of the recovery or refund to customers through the rate making process. The fair value of long-term debt is determined using a discounted cash flow method and current interest rates. The pension and OPEB obligations are valued by external actuaries using the guidelines of ASC 805, Business combinations.

Additional disclosure of APUC's critical accounting estimates is also available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board of Directors, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2016.

During the year ended December 31, 2016, APUC acquired Western Water Holdings LLC and its subsidiaries. The financial information for this acquisition is included in note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and published guidance of the U.S. Securities and Exchange Commission (SEC), management's evaluation of and conclusions on the effectiveness of internal control over financial reporting did not include the internal controls of Western Water Holdings LLC and its subsidiaries which are included in the 2016 consolidated financial statements of Algonquin Power and Utilities Corp. The acquisition constituted $623,609 and $357,680 of total and net assets, respectively, as at December 31, 2016 and $96,695 and $25,374 of revenues and net income, respectively, for the year then ended.

March 10, 2017

Ian Robertson Chief Executive Officer	David Bronicheski Chief Financial Officer

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheets as at December 31, 2016 and 2015 and the consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the two-year period ended December 31, 2016, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2016, in conformity with United States generally accepted accounting principles.

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 10, 2017 expressed an unqualified opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting.

Ernst & Young LLP

Chartered Professional Accountants,

Licensed Public Accountants

Toronto, Canada

March 10, 2017

INDEPENDENT AUDITORS' REPORT ON INTERNAL CONTROLS UNDER STANDARDS OF THE PUBLIC COMPANY ACCOUNTING OVERSIGHT BOARD (UNITED STATES)

To the Board of Directors and Shareholders of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated under the heading Internal Controls over Financial Reporting in Management's Report, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Western Water Holdings, LLC and its subsidiaries, which are included in the 2016 consolidated financial statements of Algonquin Power and Utilities Corp. and constituted $623,609 and $357,680 of total and net assets, respectively, as at December 31, 2016 and $96,695 and $25,374 of revenues and net income, respectively, for the year then ended. Our audit of internal control over financial reporting of Algonquin Power and Utilities Corp. also did not include an evaluation of the internal control over financial reporting of Western Water Holdings LLC and its subsidiaries,

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the two-year period ended December 31, 2016 and our report dated March 10, 2017 expressed an unqualified opinion thereon.

Ernst + Young LLP

Chartered Professional Accountants,

Licensed Public Accountants

Toronto, Canada

March 10, 2017

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 110,417	$ 124,817
Accounts receivable, net (note 4)	189,658	186,681
Natural gas in storage (note 1(h))	21,625	28,502
Regulatory assets (note 7)	48,440	32,213
Prepaid expenses	26,562	18,409
Derivative instruments (note 25)	76,631	15,039
Other assets (note 12)	18,519	18,073
	491,852	423,734
Property, plant and equipment, net (note 5)	4,889,946	3,877,170
Intangible assets, net (note 6)	64,989	74,477
Goodwill (note 6)	306,641	110,493
Regulatory assets (note 7)	243,524	213,102
Derivative instruments (note 25)	74,553	73,322
Long-term investments (note 8)	105,433	174,802
Deferred income taxes (note 20)	30,005	18,109
Restricted cash (note 1(f))	2,026,183	18,999
Other assets (note 12)	16,334	7,517
	$ 8,249,460	$ 4,991,725

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 90,592	$ 50,428
Accrued liabilities	308,318	193,320
Dividends payable (note 17)	38,973	41,802
Regulatory liabilities (note 7)	47,769	44,167
Long-term debt (note 9)	10,075	8,945
Other long-term liabilities and deferred credits (note 13)	43,157	36,621
Other liabilities	7,665	16,593
	546,549	391,876
Long-term debt (note 9)	3,903,340	1,477,850
Convertible debentures (note 14)	358,619	—
Regulatory liabilities (note 7)	134,965	131,180
Deferred income taxes (note 20)	288,139	175,799
Derivative instruments (note 25)	104,647	106,628
Pension and other post-employment benefits obligation (note 10)	147,845	150,094
Other long-term liabilities (note 13)	232,449	223,135
Preferred shares, Series C (note 11)	17,552	17,548
	5,187,556	2,282,234
Redeemable non-controlling interest (note 19)	29,434	25,751
Equity:		
Preferred shares (note 15(b))	213,805	213,805
Common shares (note 15(a))	1,972,203	1,808,894
Subscription receipts (note 15(a)(ii))	—	110,503
Additional paid-in capital	38,652	38,241
Deficit	(556,024)	(523,116)
Accumulated other comprehensive income (note 16)	254,927	286,737
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,923,563	1,935,064
Non-controlling interests (note 19)	562,358	356,800
Total equity	2,485,921	2,291,864
Commitments and contingencies (note 23)		
Subsequent events (notes 3, 8, 9, 14, 15 and 21)		
	$ 8,249,460	$ 4,991,725

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Year ended December 31	
	2016	**2015**
Revenue		
Regulated electricity distribution	$ 228,097	$ 224,110
Regulated gas distribution	405,735	463,651
Regulated water reclamation and distribution	181,655	78,467
Non-regulated energy sales	243,149	222,581
Other revenue	37,382	39,046
	1,096,018	1,027,855
Expenses		
Operating expenses	333,001	279,406
Regulated electricity purchased	119,825	131,647
Regulated gas purchased	142,003	217,236
Regulated water purchased	12,227	—
Non-regulated energy purchased	21,260	27,990
Administrative expenses	46,349	39,830
Depreciation and amortization	186,899	149,806
Gain on foreign exchange	(436)	(2,631)
	861,128	843,284
Operating income from continuing operations	234,890	184,571
Interest expense on convertible debentures and acquisition financing (notes 9(b) and 14)	57,630	—
Interest expense on long-term debt and others	73,962	65,993
Interest, dividend, equity and other income	(10,573)	(9,095)
Other gains	(8,555)	(5,110)
Acquisition-related costs	12,028	1,832
Loss (gain) on long-lived assets, net (note 8(e) and 18)	(3,263)	2,890
Gain on derivative financial instruments (note 25(b)(iv))	(15,849)	(2,188)
	105,380	54,322
Earnings from continuing operations before income taxes	129,510	130,249
Income tax expense (note 20)		
Current	8,461	7,310
Deferred	28,675	36,403
	37,136	43,713
Earnings from continuing operations	92,374	86,536
Loss from discontinued operations, net of tax	—	(1,032)
Net earnings	92,374	85,504
Net effect of non-controlling interests (note 19)	(38,550)	(31,976)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 130,924	$ 117,480
Series A and D Preferred shares dividend (note 17)	10,400	10,400
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 120,524	$ 107,080
Basic net earnings per share from continuing operations (note 21)	$ 0.44	$ 0.43
Basic net earnings per share (note 21)	0.44	0.42
Diluted net earnings per share from continuing operations (note 21)	0.44	0.42
Diluted net earnings per share (note 21)	$ 0.44	$ 0.42

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2016	2015
Net earnings	$ 92,374	$ 85,504
Other comprehensive income:		
Foreign currency translation adjustment, net of tax recovery of $nil and $nil, respectively (notes 1(v), 25(b)(iii) and 25(b)(iv))	(67,855)	289,035
Change in fair value of cash flow hedges, net of tax expense of $18,109 and $12,010, respectively (note 25(b)(ii))	26,754	16,165
Change in unrealized appreciation in value of available-for-sale investments	213	(73)
Change in pension and other post-employment benefits, net of tax expense of $1,433 and $4,923, respectively (note 10)	2,252	7,571
Other comprehensive (loss) income, net of tax	(38,636)	312,698
Comprehensive income	53,738	398,202
Comprehensive (loss) income attributable to the non-controlling interests	(45,376)	28,198
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 99,114	$ 370,004

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2016

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2015	$1,808,894	$213,805	$ 110,503	$ 38,241	$ (523,116)	$ 286,737	$356,800	$2,291,864
Net earnings (loss)	—	—	—	—	130,924	—	(38,550)	92,374
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	—	4,952	4,952
Other comprehensive loss	—	—	—	—	—	(31,810)	(6,826)	(38,636)
Dividends declared and distributions to non-controlling interests	—	—	—	—	(125,696)	—	(3,926)	(129,622)
Dividends and issuance of shares under dividend reinvestment plan (note 15(a)(iii))	33,862	—	—	—	(33,862)	—	—	—
Common shares issued upon conversion of subscription receipts (note 15 (a)(ii))	110,503	—	(110,503)	—	—	—	—	—
Common shares issued pursuant to share-based awards (note 15(c))	18,944	—	—	(5,505)	(4,274)	—	—	9,165
Share-based compensation	—	—	—	5,916	—	—	—	5,916
Contributions received from non-controlling interests	—	—	—	—	—	—	12,752	12,752
Non-controlling interest of acquired operating entity (note 8(c))	$ —	$ —	$ —	$ —	$ —	$ —	$237,156	$ 237,156
Balance, December 31, 2016	$1,972,203	$213,805	$ —	$ 38,652	$ (556,024)	$ 254,927	$562,358	$2,485,921

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2015

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2014	$1,633,262	$213,805	$ 110,503	$ 33,068	$ (505,305)	$ 34,213	$316,842	$1,836,388
Net earnings (loss)	—	—	—	—	117,480	—	(31,976)	85,504
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	—	3,571	3,571
Other comprehensive income	—	—	—	—	—	252,524	60,174	312,698
Dividends declared and distributions to non-controlling interests	—	—	—	—	(105,929)	—	(2,626)	(108,555)
Dividends and issuance of shares under dividend reinvestment plan	29,302	—	—	—	(29,302)	—	—	—
Common shares issued pursuant to public offering, net of costs (note 15(a)(i))	144,987	—	—	—	—	—	—	144,987
Common shares issued pursuant to share-based awards (note 15(c))	1,343	—	—	(282)	(60)	—	—	1,001
Share-based compensation	—	—	—	5,455	—	—	—	5,455
Contributions received from non-controlling interests	—	—	—	—	—	—	10,815	10,815
Balance, December 31, 2015	$1,808,894	$213,805	$ 110,503	$ 38,241	$ (523,116)	$ 286,737	$356,800	$2,291,864

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31	
	2016	**2015**
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 92,374	$ 86,536
Adjustments and items not affecting cash:		
Depreciation and amortization	195,751	151,627
Deferred taxes	28,675	36,403
Unrealized gain on derivative financial instruments	(18,689)	(1,990)
Share-based compensation expense	5,916	5,455
Cost of equity funds used for construction purposes	(2,774)	(2,424)
Pension and post-employment expense	(13,491)	(3,333)
Non-cash revenue and other income	(10,467)	550
Write-down of long-lived assets	6,259	1,781
Unrealized gain on disposal of VIE	—	220
Changes in non-cash operating items (note 24)	3,704	(11,149)
Cash used in discontinued operations	—	(1,806)
	287,258	261,870
Financing Activities		
Cash dividends on common shares	(118,145)	(79,121)
Cash dividends on preferred shares	(10,400)	(10,400)
Cash contributions from non-controlling interests	13,468	15,222
Production-based cash contributions from non-controlling interest	9,454	10,815
Cash distributions to non-controlling interests	(4,307)	(2,936)
Issuance of common shares, net of costs	1,526	144,694
Issuance of convertible debentures, net of costs	357,694	—
Proceeds from exercise of share options	18,461	—
Shares surrendered to fund withholding taxes on exercised share options	(5,218)	—
Increase in long-term debt	2,399,009	248,811
Decrease in long-term debt	(68,423)	(196,149)
Increase in other long-term liabilities	6,486	31,544
Decrease in other long-term liabilities	(4,269)	(6,182)
	2,595,336	156,298
Investing Activities		
Decrease (increase) in restricted cash	(2,007,732)	2,900
Increase in other assets	(20,501)	(2,155)
Distributions received in excess of equity income	653	1,386
Receipt of principal on notes receivable	319,160	29,273
Additions to property, plant and equipment	(405,743)	(204,195)
Increase in long-term investments	(347,901)	(138,560)
Acquisitions of operating entities	(432,699)	(3,717)
Proceeds from sale of long-lived assets	—	5,516
	(2,894,763)	(309,552)
Effect of exchange rate differences on cash	(2,231)	6,928
Increase (decrease) in cash and cash equivalents	(14,400)	115,544
Cash and cash equivalents, beginning of year	124,817	9,273
Cash and cash equivalents, end of year	$ 110,417	$ 124,817

Supplemental disclosure of cash flow information:	**2016**	**2015**
Cash paid during the year for interest expense	$ 131,783	$ 69,610
Cash paid during the year for income taxes	$ 13,369	$ 6,153
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	$ 146,301	$ 44,834
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 35,409	$ 30,645
Issuance of common shares upon conversion of subscription receipts	$ 110,503	$ —
Acquisition of equity investments in exchange for loan receivable	$ 26,035	$ —

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's operations are organized across two primary North American business units consisting of the Renewable Generation Group and the Liberty Utilities Group. The Renewable Generation Group ("Renewable Generation Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group ("Liberty Utilities Group") owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

1. Significant accounting policies

(a) Basis of preparation

The accompanying consolidated financial statements and notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosure required under Regulation S-X provided by the U.S. Securities and Exchange Commission.

(b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC, its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary (note 1(l)). Intercompany transactions and balances have been eliminated. Interests in subsidiaries owned by third parties are included in non-controlling interests (note 1(q)).

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets which meet the definition of a business as business combinations. The determination of whether the definition of a business has been met for a development stage project depends on the stage of development (permitting, customer contracting, financing, construction) and the significance of the development risk with respect to achieving commercial operation. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred. When the set of activities does not represent a business, the transaction is accounted for as an asset acquisition and includes acquisitions costs.

Intangible assets acquired are recognized separately at fair value if they arise from contractual or other legal rights or are separable. Power sales contracts are amortized on a straight-line basis over the remaining term of the contract ranging from 6 to 25 years from the date of acquisition. Interconnection agreements are amortized on a straight-line basis over their estimated life of 40 years. Customer relationships are amortized on a straight-line basis over their estimated life of 40 years.

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in the rate-base on which regulated utilities are allowed to earn a return and is not amortized.

As at September 30 of each year, the Company assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(d) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities 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 making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge or credit against earnings for any remaining regulatory assets or liabilities. The impact could be material to the Company's reported financial condition and results of operations.

The electric, gas and water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and National Association of Regulatory Utility Commissioners.

(e) Cash and cash equivalents

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

(f) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. As of December 31, 2016, restricted cash also includes cash of U.S. $1,495,774 transfered to a paying agent for purposes of distribution to holders of common shares of Empire on January 1, 2017 (note 3(a)). Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance sheet credit exposure related to its customers.

(h) Natural gas in storage

Natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities and some generating facilities. Existing rate orders (note 7(c)) and other contracts allow the Company to pass through the cost of gas purchased directly to the customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the recoverable value of gas in storage does not fall below the cost to the Company.

(i) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost. Supplies and consumables inventory is included in other current assets.

(j) Property, plant and equipment

Property, plant and equipment are recorded at cost. Capitalization of development projects begins when management, together with the relevant authority, authorized and has committed to the funding of a project and it is probable that costs will be realized through the use of the asset or ultimate construction and operation of a facility. Project development costs for rate-regulated entities, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized either as property, plant and equipment or regulatory asset when it is determined that recovery of such costs through regulated revenue of the completed project is probable.

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

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for funds used during construction ("AFUDC") for regulated property. Where possible, individual components are recorded and depreciated separately in the books and records of the Company. Plant and equipment under capital leases are initially recorded at cost determined as the present value of minimum lease payments.
AFUDC represents the cost of borrowed funds and a return on other funds. Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835, Interest. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend, equity and other income on the consolidated statements of operations.

	2016	2015
Interest capitalized on non-regulated property	**$ 3,259**	$ 1,189
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,167**	1,657
Allowance for equity funds	**2,774**	2,425
Total	**$ 7,200**	$ 5,271

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Cost incurred for major expenditures or overhauls that occur at regular intervals over the life of an asset are capitalized and depreciated over the related interval. Maintenance and repair costs are expensed as incurred.

Investment tax credits and government grants related to capital expenditures are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 13(a)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Investment tax credits and government grants related to operating expenses such as maintenance and repairs costs are recorded as a reduction of the related expense.

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method with the exception of certain wind assets, as described below. The ranges of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2016	2015	2016	2015
Generation	**3 - 60**	3 - 60	**32**	32
Distribution	**5 - 100**	5 - 100	**41**	42
Equipment	**5 - 50**	5 - 50	**11**	12

The Company uses the unit-of-production method for certain components of its wind generating facilities where the useful life of the component is directly related to the amount of production. The benefits of components subject to wear and tear from the power generation process are best reflected through the unit-of-production method. The Company generally uses wind studies prepared by third parties to estimate the total expected production of each component.

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Liberty Utilities Group are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operations in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(k) Impairment of long-lived assets

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets held and used: Recoverability of assets expected to be held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets held for sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(l) Variable interest entities

The Company performs analysis to assess whether its operations and investments represent VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated (note 8).

The Company has equity and notes receivable interests in two power generating facilities. APUC has determined that both entities are considered a VIE mainly based on total equity at risk not being sufficient to permit the legal entity to finance its activities without additional subordinated financial support. The key decisions that affect the generating facilities' economic performance relate to siting, permitting, technology, construction, operations and maintenance and financing. As APUC has both the power to direct the activities of the entities that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entities that could potentially be significant to the entity, the Company is considered the primary beneficiary.

Total net book value of generating assets and long-term debt of these facilities amounts to $87,189 (2015 - $104,243) and $40,398 (2015 - $62,138), respectively. The debt only has recourse over the generating assets. The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $29,132 (2015 - $18,651), operating expenses and amortization of $6,175 (2015 - $5,645) and interest expense of $4,064 (2015 - $4,407).

(m) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are accounted using the equity method. Equity-method investments are initially measured at cost including transaction costs and interest when applicable. APUC records its share in the income or loss of its investees in interest, dividend, equity and other income in the consolidated statements of operations.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable are initially recorded at cost, which is generally face value. Subsequent to acquisition, the notes receivable are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. Interest from long-term investments is recorded as earned and collectability of both the interest and principal are reasonably assured.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate.

1. Significant accounting policies (continued)

(n) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, and other post-employment benefit ("OPEB") plans for its various employee groups in Canada and the United States. Employer contributions to the defined contribution pension plans are expensed as employees render service. The Company recognizes the funded status of its defined benefit pension plans and OPEB plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

(o) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, during construction or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation and amortization expense on the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the obligation.

(p) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the award granted, adjusted for estimated forfeitures. The compensation cost is recorded as administrative expense in the consolidated statements of operations and contributed surplus in equity. Contributed surplus is reduced as the awards are exercised, and the amount initially recorded in contributed surplus is credited to common shares.

(q) Non-controlling interests

Non-controlling interests represent the portion of equity ownership in subsidiaries that is not attributable to the equity holders of APUC. Non-controlling interests are initially recorded at fair value and subsequently adjusted for the proportionate share of earnings and other comprehensive income ("OCI") attributable to the non-controlling interests and any dividends or distributions paid to the non-controlling interests.

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a consolidated subsidiary, the acquisition of the non-controlling interest is accounted for as an equity transaction. No gain or loss is recognized in net earnings or comprehensive income as a result of changes in the non-controlling interest, unless a change results in the loss of control by the Company.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations ("LLC") and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units" or "Class A Equity Investors") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLC and partnership's agreements have liquidation rights and priorities that are different from the underlying percentages ownership interests. In those situations, simply applying the percentage ownership interest to GAAP net income in order to determine earnings or losses would not accurately represent the income allocation and cash flow distributions that will ultimately be received by the investors. As such, the share of earnings attributable to the non-controlling interest holders in these entities is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting (note 19).

1. Significant accounting policies (continued)

(q) Non-controlling interests (continued)

The HLBV method uses a balance sheet approach. A calculation is prepared at each balance sheet date to determine the amount that Class A Equity Investors would receive if an equity investment entity were to liquidate all of its assets and distribute that cash to the investors based on the contractually defined liquidation priorities. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period is the Class A Equity Investors' share of the earnings or losses from the investment for that period. Due to certain mandatory liquidation provisions of the LLC and partnership agreements, this could result in a net loss to APUC's consolidated results in periods in which the Class A Equity Investors report net income. The calculation varies in its complexity depending on the capital structure and the tax considerations of the investments.

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. As needed, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

(r) Recognition of revenue

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Qualifying renewable energy projects receive renewable energy credits ("REC") and solar renewable energy credits ("SRECs") for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The REC and SREC can be traded and the owner of the REC or SREC can claim to have purchased renewable energy. RECs and SRECs are primarily sold under fixed contracts, and revenue for these contracts is recognized at the time of generation. Any REC's or SRECs generated above contracted amounts are held in inventory, with the offset recorded as a decrease in operating expenses.

Revenue related to utility electricity and natural gas sales and distribution are recorded when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Revenue for certain of the Company's regulated utilities is subject to revenue decoupling mechanisms approved by their respective regulators which require to charge approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7(e)).

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and wastewater collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rate and if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

Revenue is recorded net of sales taxes.

1. Significant accounting policies (continued)

(s) Foreign currency translation

APUC's reporting currency is the Canadian dollar.

The Company's U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenue and expenses are translated using average rates for the period.

Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

(t) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(u) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost. Long-term debt and Series C preferred shares are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the asset's carrying value at inception. Transaction costs related to a recognized debt liability are presented in the consolidated balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts and premiums. Costs of arranging the Company's revolving credit facilities and intercompany loans are recorded in other assets. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities and intercompany loans are amortized on a straight-line basis over the term of the respective instrument.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities on the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to some of its financial instruments used to manage its foreign currency risk exposure, interest risk and price risk exposure associated with sales of generated electricity.

1. Significant accounting policies (continued)

(u) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized in OCI. The ineffective portion is immediately recognized in earnings. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount remaining in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecasted transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

The Company's electric distribution and thermal generation facilities enter into power and gas purchase contracts for load serving and generation requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an ongoing basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(v) Fair value measurements

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

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1, inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

(w) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(x) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these consolidated financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and, the fair value of financial instruments. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB Issued ASU 2017-03 Accounting Changes and Error Corrections (Topic 250) and Investments—Equity Method and Joint Ventures (Topic 323) to enhance disclosures of new accounting standards, including a comparison to current accounting policies, and the progress status of implementation. This ASU applies to ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606); ASU No. 2016-02, Leases (Topic 842); and ASU 2016-03, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, and subsequent amendments. The Company has enhanced its disclosures regarding the impact that recently issued accounting standards will have on the Company's consolidated financial statements when such standards are adopted in a future period.

The FASB issued ASU 2016-19, Technical Corrections and Improvements, to clarify the codification, correct unintended application of guidance, or make minor improvements to the codification. The adoption of this ASU in the fourth quarter of 2016 had no impact on the Company's consolidated financial statements.

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 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 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 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 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 consolidated financial statements.

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. The adoption of this standard as of December 31, 2016 had no impact on the Company's consolidated financial statements. Its implementation leveraged existing financial reporting processes.

2. Recently issued accounting pronouncements (continued)

(a) Recently adopted accounting pronouncements (continued)

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 consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2017-04 Business Combinations (Topic 350): Intangibles - Goodwill and Other (Topic 350) Simplifying the Test for Goodwill Impairment. The update is intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. The standard is effective for fiscal years and interim periods beginning after December 15, 2019.

The FASB issued ASU 2017-01 Business Combinations (Topic 805): Clarifying the Definition of a Business. The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is effective for fiscal years and interim periods beginning after December 15, 2017.

The FASB issued ASU 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash to eliminate current diversity in practice in the classification and presentation of changes in restricted cash on the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The Company currently present changes in restricted cash as investing activities. The adoption of this standard will change the presentation of restricted cash on the consolidated statement of cash flows.

The FASB issued ASU 2016-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This ASU amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The 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 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory. The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. Current GAAP prohibits the recognition of current and deferred income taxes on these transactions until the asset has been sold to an outside party. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

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

2. Recently issued accounting pronouncements (continued)

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

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

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 adoption of this standard is expected to have no material impact on the Company's consolidated financial statements. The Company intends to continue with its current accounting policy to record the stock-based compensation expense adjusted for estimated forfeitures.

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

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

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

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

2. Recently issued accounting pronouncements (continued)

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

The FASB issued a new revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. The core principal of the new accounting guidance is that an entity should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASC 606 will also require significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. This new revenue standard is required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company has not elected to early adopt. The Company has identified existing customer contracts and tariffs that are within the scope of the new guidance and has begun an assessment in order to determine the method of adoption and the impact it may have on its consolidated financial statements. The Company also closely monitors outstanding industry specific interpretative issues, including contributions in aid of construction and collectability of sales to low income customers.

3. Business acquisitions and development projects

(a) Acquisition of Empire

Subsequent to year end, on January 1, 2017, the Company completed the acquisition of The Empire District Electric Company and its subsidiaries ("Empire"). Empire is a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

The purchase price of approximately U.S.$2,400,000 for the acquisition of Empire consists of cash payment to Empire shareholders of U.S.$34.00 per common share and the assumption of approximately U.S.$855,000 of debt. The cash payment was funded with the acquisition facility for an amount of U.S.$1,336,440 (note 9(b)), proceeds received from the initial instalment of convertible debentures (note 14) and existing credit facility. The costs related to the acquisition have been expensed through the consolidated statements of operations.

Due to the timing of the acquisition, the Company has not completed the fair value measurements. The Company will continue to review information and perform further analysis prior to finalizing the allocation of the consideration paid to the fair value of the assets acquired and liabilities assumed and preparing the related pro forma information.

(b) Luning Solar Facility

Luning Utilities (Luning Holdings) LLC (the "Luning Holdings") is owned by the Calpeco Electric System. During 2016, a tax equity agreement was executed. The Class A partnership units are owned by a third-party tax equity investor who funded U.S.$7,826 as of December 31, 2016 and an amount of U.S.$31,212, subsequent to year-end, on February 17, 2017. With its interest, the tax equity investor will receive the majority of the tax attributes associated with the Luning Solar project. The Company accounts for this interest as "Redeemable non-controlling interest" outside of permanent equity on the consolidated balance sheets. Redemption is not considered probable as of December 31, 2016.Subsequent to year-end, on February 15, 2017, Luning Holdings obtained control of the Luning Solar Facility as it achieved commercial operation. The 50MWac solar generating facility is located in Mineral County, Nevada.

(c) Bakersfield II Solar Facility

On December 14, 2016, the Company completed construction and placed in service a 10 MWac solar powered generating facility located adjacent to the Company's 20 MWac Bakersfield I Solar Facility in Kern County, California ("Bakersfield II Solar Facility"). Commercial operations as defined by the power purchase agreement was reached on January 11, 2017.

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

3. Business acquisitions and development projects (continued)

(c) Bakersfield II Solar Facility (continued)

The Bakersfield II Solar Facility is controlled by a subsidiary of APUC (the "Bakersfield II Partnership"). The Class A partnership units are owned by a third-party tax equity investor who funded U.S.$2,454 on November 29, 2016 and approximately U.S.$9,800 on February 28, 2017. With its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

(d) Wind Turbine Components Purchase

In the fourth quarter of 2016, the Company purchased approximately $75,000 of wind turbine components that will qualify between 500 MW and 700 MW of new wind powered projects for the full U.S.$0.023/kWh renewable energy production tax credit under the safe harbor guidelines established by the U.S. Internal Revenue Service, provided that such projects are placed in service before the end of 2020.

(e) 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. Those three utilities were named Park Water Company, Apple Valley Ranchos Water Co. and Mountain Water Company. The total purchase price for the Park Water System is $353,077 (U.S.$249,540), net of the debt assumed of U.S.$91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed in the consolidated statements of operations.

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

Working capital	$ 2,045
Property, plant and equipment	345,254
Notes receivable	1,781
Goodwill	210,463
Regulatory assets	54,548
Other assets	185
Long-term debt	(146,727)
Regulatory liabilities	(3,758)
Pension and OPEB	(18,747)
Deferred income tax liability, net	(51,795)
Other liabilities	(40,172)
Total net assets acquired	$ 353,077

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions. Immaterial changes to the initial allocation were recorded during 2016.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Distribution segment.

3. Business acquisitions and development projects (continued)

(e) Acquisition of Park Water System (continued)

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

On December 22, 2015, various developers filed a lawsuit in Missoula County District Court against Mountain Water Company and the city of Missoula. The lawsuit pertains to Funded By Other (FBO) contracts between each developer and Mountain Water Company. Under those FBO contracts, the developers paid for facilities to provide water service and Mountain Water Company agreed to refund such amounts over a 40 year period. These FBO contracts are recorded on the balance sheet of Mountain Water and reflect a non-discounted liability of U.S.$23,108 at the acquisition date. On February 21, 2017, the Montana district court issued an order finding that Mountain Water Company is liable for the developer refunds even after the city of Missoula condemns and takes possession of the utility assets. The amount of the refund obligations to be paid by Mountain Water Company is subject to further proceedings in the Montana district 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 $96,695 and pre-tax net earnings of $25,374 to the Company's consolidated financial results for the year ended December 31, 2016.

(f) Commercial operation of Morse Wind Facility

In 2015, the Company completed construction of a 23 MW wind generating facility located near Morse, Saskatchewan ("Morse Wind Facility"). Sale of power to the utility commenced in March 2015 at rates equivalent to those under the power purchase agreement. Commercial operation date as defined in the power purchase agreement occurred on April 22, 2015. The cost of the generating assets of $65,016 is recorded as property, plant and equipment on the consolidated balance sheets while $16,709 is recorded as intangible assets, for a total investment of $81,725. The weighted average useful life of the Morse Wind Facility is 35 years.

(g) Acquisition of New Hampshire Gas

On January 2, 2015, the Company completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is U.S.$3,161.

(h) Commercial operation of Bakersfield Solar I Facility

In 2014, the Company completed construction of a 20 MWac solar powered generating facility located in Kern County, California ("Bakersfield I Solar Facility") which was placed in service on December 31, 2014. The Bakersfield I Solar Facility started selling power at the power purchase agreement price on May 15, 2015. The cost of these generating assets amounts to U.S.$59,281 and is recorded as property, plant and equipment on the consolidated balance sheets. The weighted average useful life of the Bakersfield Solar I Facility is 34 years.

The Bakersfield I Solar Facility is controlled by a subsidiary of APUC (the "Bakersfield I Partnership"). The Class A partnership units are owned by a third-party tax-equity investor who funded a total of U.S.$22,438 to the project. With its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project.

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

3. Business acquisitions and development projects (continued)

(h) Commercial operation of Bakersfield Solar I Facility (continued)

During a six-month period in year 2020, the Tax Investor has the right to withdraw from the Bakersfield I Solar Facility and require the Company to redeem its remaining interests for cash. As a result, the Company accounts for this interest as "Redeemable non-controlling interest" outside of permanent equity on the consolidated balance sheets. Redemption is not considered probable as of December 31, 2016.

(i) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, the Company acquired the 109.5 MW Shady Oaks wind-powered generating facility ("Shady Oaks Wind Facility"). The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices which are expected to be finalized in 2017. Changes in measurement of the final purchase price adjustment subsequent to December 31, 2013, the end of the business combination measurement period, are recorded in current period operations. To that effect, no gain or loss was recognized in 2016 (2015 - U.S.$nil).

4. Accounts receivable

Accounts receivable as of December 31, 2016 include unbilled revenue of $57,822 (2015 - $49,002) from the Company's regulated utilities. Accounts receivable as of December 31, 2016 are presented net of allowance for doubtful accounts of $7,064 (2015 - $7,966).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2016

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,613,267	$ 419,227	$ 2,194,040
Distribution	2,638,488	462,454	2,176,034
Land	60,868	—	60,868
Equipment and other	139,961	44,700	95,261
Construction in progress			
Generation	197,405	—	197,405
Distribution	166,338	—	166,338
	$ 5,816,327	$ 926,381	$ 4,889,946

2015

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,138,748	$ 358,200	$ 1,780,548
Distribution	2,075,059	265,741	1,809,318
Land	23,258	—	23,258
Equipment and other	129,555	37,443	92,112
Construction in progress			
Generation	68,265	—	68,265
Distribution	103,669	—	103,669
	$ 4,538,554	$ 661,384	$ 3,877,170

Generation assets include cost of $142,246 (2015 - $158,514) and accumulated depreciation of $39,958 (2015 - $38,507) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,117 (2015 - $2,117).

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

5. Property, plant and equipment (continued)

On September 16, 2016, Revenu Québec issued a notice of assessment approving the Company's Canadian renewable and conservation expense ("CRCE") refundable tax credit claim for the St Damase wind facility in the amount of $14,086. The Company received the tax credit in cash on October 6, 2016. The tax credit together with interest received was recorded, net of related costs, as a reduction of the related assets. As at December 31, 2016, investment tax credits, CRCE tax credit, government grants and contributions received in aid of construction of $49,794 (2015 - $9,623) have been credited to the cost of the assets.

Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

6. Intangible assets and goodwill

Intangible assets consist of the following:

2016

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 72,207	$ 44,641	$ 27,566
Customer relationships	35,979	10,999	24,980
Interconnection agreements	13,000	557	12,443
	$ 121,186	$ 56,197	$ 64,989

2015

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 75,239	$ 40,244	$ 34,995
Customer relationships	37,083	10,371	26,712
Interconnection agreements	13,000	230	12,770
	$ 125,322	$ 50,845	$ 74,477

Estimated amortization expense for intangible assets for the next year is $3,880, $3,530 in year two, $3,080 in year three, $2,220 in year four and $2,220 in year five.

Changes in goodwill are as follows:

	Distribution
Balance, January 1, 2015	$ 92,328
Business acquisitions	290
Foreign exchange	17,875
Balance, December 31, 2015	$ 110,493
Business acquisitions (note 3(e))	210,463
Foreign exchange	(14,315)
Balance, December 31, 2016	$ 306,641

7. 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 consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

On January 31, 2017, the Georgia Public Service Commission approved a Final Order for the Peach State Gas System of a U.S.$686 annual revenue increase effective February 1, 2017.

On December 8, 2016, the California Public Utilities Commission approved a Final Order for the CalPeco Electric System of a U.S.$8,318 annual revenue increase effective January 1, 2017 for services rendered on or after January 1, 2016. The Commission also required CalPeco Electric System to apply the flow through method of accounting for income tax expense related to repair costs for regulatory purposes (note 7(g)).

On November 21, 2016, the Arizona Corporation Commission approved a Final Order for the Bella Vista Water System and Rio Rico Water & Sewer System of a combined revenue increase of U.S.$1,935 effective November 1, 2016.

In April 2016, the Granite State Electric System filed a general rate application. In June 2016, the New Hampshire Public Utility Commission approved a temporary annual rate increase of U.S.$2,355, effective July 1, 2016. A Final Order is expected in Q2 2017.

On April 22, 2016, the Arizona Corporation Commission approved a Final Order for the Black Mountain Sewer System of a U.S.$175 annual 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 annual 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 and an additional U.S. $500 effective March 1, 2017.

On June 26, 2015, the EnergyNorth Gas System received a Final Order from the New Hampshire Public Utility Commission approving a U.S.$12,400 annual revenue increase effective July 1, 2015.

On March 12, 2015, the Pine Bluff Water System received a Final Order from the Arkansas Public Service Commission approving an annual revenue increase of U.S.$1,087 effective March 15, 2015.

On February 11, 2015, the Midstates Gas System received a Final Order from the Illinois Commerce Commission approving an annual revenue increase of U.S.$4,625 effective February 20, 2015.

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

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	2016	2015
Regulatory assets		
Environmental remediation (a)	$ **104,160**	$ 116,747
Pension and post-employment benefits (b)	**75,527**	69,537
Commodity costs adjustment (c)	**6,972**	7,643
Rate case costs (d)	**8,572**	6,535
Rate adjustment mechanism (e)	**40,602**	14,804
Debt premium (f)	**25,173**	5,132
Taxes (g)	**10,182**	5,926
Other	**20,776**	18,991
Total regulatory assets	$ **291,964**	$ 245,315
Less current regulatory assets	**(48,440)**	(32,213)
Non-current regulatory assets	$ **243,524**	$ 213,102
Regulatory liabilities		
Cost of removal (h)	$ **110,330**	$ 107,988
Rate-base offset (i)	**20,946**	24,984
Commodity costs adjustment (c)	**33,891**	32,423
Pension and post-employment benefits (b)	**5,481**	397
Taxes (g)	**1,501**	188
Other	**10,585**	9,367
Total regulatory liabilities	$ **182,734**	$ 175,347
Less current regulatory liabilities	**(47,769)**	(44,167)
Non-current regulatory liabilities	$ **134,965**	$ 131,180

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 13(b)) are recovered through rates over a period of 7 years and are subject to an annual cap.

(b) Pension and post-employment benefits

As part of certain business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. An amount of $29,037 relates to an acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order to be received on completion of the next general rate case. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation Non-retirement Post-employment Benefits and ASC 715 Compensation Retirement Benefits before the transfer to regulatory asset occurred. The pension and post-employments benefits liability is related to tracking accounts pertaining primarily to Park Water Company. The amounts recorded in these accounts occur when actual expenses have been less than adopted and refunds are expected to occur in future periods.

(c) Commodity costs adjustment

The revenue from the utilities includes a component which is designed to recover the cost of electricity and natural gas through rates charged to customers. To the extent actual costs of power or natural gas purchased differ from power or natural gas costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets.

7. Regulatory matters (continued)

(c) Commodity costs adjustment (continued)

These differences are reflected in adjustments to rates and recorded as an adjustment to cost of electricity and natural gas in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25(b)(i)) are recoverable through the commodity costs adjustment.

(d) Rate case costs

The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(e) Rate adjustment mechanism

Revenue for Calpeco Electric System, Park Water System, Peach State Gas System and New England Gas Systems are subject to a revenue decoupling mechanism approved by their respective regulator which require charging approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but to be collected over a period not exceeding 24 months are accrued upon approval of the Final Order.

(f) Debt premium

Debt premium on acquired debt is recovered as a component of the weighted average cost of debt.

(g) Taxes

Under flow-through accounting, the income tax effects of certain tax items are reflected in cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. This regulatory treatment was applied to the tax benefit generated by repair costs that were previously capitalized for tax purposes in CalPeco Electric System's Final Order issued December 8, 2016. In this instance, the agreed upon rate increase was less than it would have been absent the flow-through treatment by U.S. $1,501. A regulatory asset established to reflect the future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, a tax benefit is recorded consistent with the flow-through method with respect to costs considered repairs for income tax purposes and capitalized for book purposes.

(h) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(i) Rate-base offset

The regulators imposed a rate-base offset that will reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of 10-16 years.

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company generally earns carrying charges on the regulatory balances related to commodity cost adjustment, retroactive rate adjustments and rate case costs.

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

8. Long-term investments

Long-term investments consist of the following:

		2016		2015
Equity-method investees				
Red Lily I Wind Facility (a)	$	23,504	$	—
Deerfield Wind Project (b)		34,727		2,240
Odell Wind Facility (c)		—		42,287
Amherst Island Wind Project (d)		558		—
Interests in natural gas pipeline developments (e)		—		5,623
Other		5,630		2,323
	$	64,419	$	52,473
Notes receivable				
Development loans (f)	$	32,125	$	96,924
Red Lily Senior loan Tranche 2, interest at 6.31% (a)		—		11,588
Red Lily Subordinated loan Tranche 1, interest at 12.5% (a)		—		6,565
Other		6,058		4,306
		38,183		119,383
Available-for-sale investment		169		2,946
Other investments		2,662		—
Total long-term investments	$	105,433	$	174,802

(a) Red Lily I Wind Facility

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

The Company's investment in the Red Lily I Wind Facility as at January 1, 2015 was in the form of participation in a portion of the senior and subordinated debt facilities of the Partnership. On February 23, 2016, a second tranche of subordinated loan for an amount equal to $15,588 was advanced to the Partnership by the Company. The proceeds from this additional subordinated debt were used by the Partnership to repay Tranche 2 of the Partnership's senior debt, including the Company's portion.

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

Due to certain participating rights being held by the minority investor, the decisions which most significantly impact the economic performance of Red Lily I require unanimous consent. As such, APUC is deemed, under U.S. GAAP, to not have control over the Partnership. As APUC exercises significant influence over operating and financial policies of Red Lily I, the Company accounts for the Partnership using the equity method. The Red Lily I Wind Facility contributed equity income of $1,288 to the Company's consolidated financial results from acquisition to December 31, 2016.

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

8. Long-term investments (continued)

(b) Deerfield Wind Project

On October 19, 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.

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. On October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S.$262,900 and a tax equity agreement was executed. Concurrently, each member contributed another U.S.$19,891 to the capital of Deerfield SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments at any time prior to the date that is 90 days following commencement of operations expected early 2017. The interest capitalized during the year ended December 31, 2016 to the investment while the Deerfield Wind Project is under construction amounts to $6,072 (2015 - $94).

As of December 31, 2016, Deerfield SponsorCo is considered a VIE namely due to the low level of its equity at that point. The Company is not considered the primary beneficiary of Deerfield SponsorCo as the two members have joint control and all decisions must be unanimous. As APUC exercises significant influence over operating and financial policies of Deerfield SponsorCo, the Company is accounting for the entity as an equity method investment. As at December 31, 2016, the Company's maximum exposure to loss of $171,239 is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(f).

Construction was completed subsequent to year-end and sale of power to the utility under the power purchase agreement started on February 21, 2017.

(c) Odell Wind Facility

Up to September 15, 2016, the Company held a 50% equity interest in Odell SponsorCo LLC, which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Facility") in the state of Minnesota.

Construction was completed during the year and sale of power to the utility under the power purchase agreement started on July 29, 2016. The interest capitalized during the year ended December 31, 2016 to the equity-method investment while the Odell Wind Facility was under construction amounts to $3,331 (2015 - $4,415). On August 5, 2016, tax equity financing was provided to the Odell Wind Facility by two U.S. financial institutions in the amount of U.S. $180,000.

On September 15, 2016, the Company acquired the remaining 50% interest in Odell SponsorCo LLC for U.S.$26,500 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting, which requires, that the fair value of assets acquired, liabilities assumed and non-controlling interest in the subsidiary, be recognized on the consolidated balance sheets as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(f)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of nil was recorded on acquisition.

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

Working capital	$	11,836
Property, plant and equipment		469,222
Asset retirement obligation		(4,812)
Deferred tax liability		(4,273)
Non-controlling interest (tax equity investors)		(237,156)
Net assets	$	234,817

8. Long-term investments (continued)

(d) Amherst Island Wind Project

Windlectric Inc. ("Windlectric") owns a 75 MW construction-stage wind development project ("Amherst Island Wind Project") in the province of Ontario. On December 20, 2016, Windlectric, a wholly owned subsidiary of the Company at the time, issued fifty percent of its common shares for $50 to a third party and as a result is no longer controlled by APUC. The Company holds an option to acquire the remaining common shares at a fixed price any time prior to the date that is 90 days following commencement of operations which is expected in 2018.

Windlectric is considered a VIE namely due to the low level of equity at risk at that point. The Company is not considered the primary beneficiary of Windlectric as the two shareholders have joint control and all decisions must be unanimous. As such, on the transaction date, the Company deconsolidated the assets and liabilities of Windlectric and recorded its retained non-controlling investment in equity and notes receivable and payable at fair value. A net gain of nil was recorded on acquisition. The Company is accounting for its investment in the joint venture under the equity method. As of December 31, 2016, the Company's maximum exposure to loss of $159,993 is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(f).

(e) Natural gas pipeline developments

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

(f) Development loans

The Company entered into a committed loan and credit support facility with Odell SponsorCo, Deerfield SponsorCo and Windlectric (collectively, the "Joint Ventures"). During construction, the Company is obligated to provide Joint Ventures with cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the Joint Ventures' Wind Projects. The loans bear interest at an annual rate of 7%-10% on outstanding principal amount until commercial operation date and either mature on that date or 5% thereafter until maturity date. The letters of credit are charged an annual fee of 2% on their stated amount. Any loan outstanding to Joint Ventures, to the extent not otherwise repaid earlier, is repayable in cash within 30 days of the fifth anniversary of the commercial operation date for Odell SponsorCo and Deerfield SponsorCo and December 31, 2018 for Windlectric.

As of December 31, 2015, the Company had outstanding loans of U.S.$62,751 from Odell SponsorCo. Following acquisition of control of Odell SponsorCo LLC (note 8(c)), amounts advanced to the Odell Wind Project were eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in other comprehensive income effective August 5, 2016.

As of December 31, 2016, the Company had outstanding loans of U.S.$1,789 (2015 - U.S.$7,281) from Deerfield SponsorCo for development costs of the Joint Venture' Wind Project.

Following the deconsolidation of Windlectric (note 8(d)) on December 20, 2016, amounts advanced by the Company to Windlectric are no longer eliminated and instead are classified as notes receivable. As of December 31, 2016, the Company had outstanding loans of $29,723 from Windlectric.

As of December 31, 2016, the following credit support was issued by the Company: $26,854 letters of credit and guarantees of obligations on behalf of the Joint Ventures, to the utilities under the PPAs; a guarantee of the obligations of the Joint Ventures under the wind turbine, transmission line, transformer, and other supply agreements; a guarantee of the obligations of the Joint Ventures under the engineering, procurement, and construction management agreements; a U.S.$7,614 surety bond and guarantee of the obligations of the Deerfield Wind Project under the decommissioning plan; a U.S.$31,000 letter of credit and guarantee of the obligations of Deerfield SponsorCo under the construction financing agreement . The initial value of the guarantee obligations is recognized under other long-term liabilities and was valued at $429 using a probability weighted discounted cash flow (level 3).

No interest revenue is accrued on the loans due to insufficient collateral in the Joint Ventures.

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

9. Long-term debt

Long-term debt consists of the following:

Borrowing type	Weighted average coupon	Maturity	Par value	2016	2015
Senior Unsecured Revolving Credit Facilities	—	2017-2019	N/A	**$ 242,947**	$ 27,300
Senior Unsecured Bank Credit Facilities	—	2017-2019	N/A	**2,140,122**	—
Canadian Dollar Borrowings					
Senior Unsecured Notes	4.99%	2018-2022	$ 490,000	**487,389**	481,991
Senior Secured Project Notes	10.29%	2020-2027	$ 35,600	**35,600**	37,347
U.S. Dollar Borrowings					
Senior Unsecured Notes	4.16%	2017-2045	US$525,000	**700,600**	721,581
Senior Unsecured Utility Notes	5.68%	2017-2028	US$130,709	**174,206**	186,446
Senior Secured Utility Bonds	6.97%	2020-2043	US$ 83,500	**132,551**	32,130
				$ 3,913,415	$ 1,486,795
Less: current portion				**(10,075)**	(8,945)
				$ 3,903,340	$ 1,477,850

Long-term debt issued at a subsidiary level relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Long-term debt whether or not collateralized 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.

(a) Senior unsecured revolving credit facilities

APUC has a senior unsecured revolving credit of U.S.$65,000 maturing November 19, 2017. The interest rate is equal to the bankers' acceptance or LIBOR plus a credit spread.

Liberty Utilities Co. has a senior unsecured revolving credit facility of U.S.$200,000 maturing September 30, 2018. The interest rate is equal to LIBOR plus a credit spread.

Algonquin Power Co. has a senior unsecured revolving credit facility of $350,000 maturing July 31, 2019. The interest rate is equal to the bankers' acceptance or LIBOR plus a credit spread.

Algonquin Power Co. has an extendible one-year letter of credit facility agreement. The facility provides for issuances of letters of credit up to a maximum of $50,000 and U.S.$30,000. If the facility is not extended at maturity, cash collateral equal to letters of credit outstanding at that date would be posted by the Company.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(b)), the Company assumed U.S. $4,250 of debt outstanding under its revolving credit facilities. Shortly after the closing of the acquisition, the Park Water System repaid and closed the revolving credit facilities.

(b) Senior unsecured bank credit facilities

On December 30, 2016, in connection with the acquisition of Empire (note 3(a)), the Company drew U.S. $1,336,440 from the acquisition facility it obtained from a syndicate of banks earlier in 2016. The non-revolving term credit facilities are comprised of a U.S.$1,065,000 debt facility and a U.S.$271,440 equity facility both repayable in full on December 30, 2017. The funds drawn were transferred to a paying agent on December 30, 2016 for purposes of distribution to holders of the common shares of Empire (note 3(a)) on January 1, 2017. The total amount of cash held by the paying agent of U.S.$1,495,774 is comprised of this acquisition facility draw of U.S.$1,336,440 and cash proceeds received from the initial instalment of convertible debentures (note 14) and is presented as restricted cash on the consolidated balance sheets. Subsequent to year end, on February 7, 2017, upon receipt of the Final Instalment from the Debentures (note 14) the Company repaid U.S. $567,650 under the acquisition Facility.

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

9. Long-term debt (continued)

(b) Senior unsecured bank credit facilities (continued)

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, 2018.

As part of the Park Water System' s acquisition on January 8, 2016 (note 3(e)), the Company assumed U.S. $22,500 of debt outstanding under a non-revolving term credit facility. 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.

(c) Canadian dollar senior unsecured notes

Subsequent to year end, on January 17, 2017 APCo issued $300,000 senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount.

(d) U.S. dollar senior unsecured utility notes

Subsequent to year-end, on February 8, 2017, the U.S.$707 Bella Vista Water unsecured notes were fully repaid.

Subsequent to year end, on March 1, 2017, Liberty Utilities Group's financing entity entered into an agreement to issue U.S.$750,000 senior unsecured notes in six tranches. The closing of the offering is scheduled to occur before the end of March 2017 with the proceeds to be applied to repay the acquisition facility (note 9(b)) and other existing indebtedness. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%.

On April 30, 2015, the Liberty Utilities Group's financing entity issued U.S.$160,000 of senior unsecured 30-year notes bearing a coupon of 4.13% via a private placement in the U.S.. The funds were drawn in two tranches: U.S.$90,000 was drawn on closing and U.S.$70,000 was drawn on July 15, 2015.

(e) U.S. dollar senior secured notes

On May 12, 2015, the U.S.$76,000 senior debt for the Shady Oaks Wind Facility was repaid.

(f) U.S. Senior Secured Utility Bonds

As part of the Park Water System' s acquisition on January 8, 2016 (note 3(e)), the Company assumed U.S.$65,000 of debt outstanding under six tranches of first mortgage bonds. The First Mortgage bonds have maturities ranging between 2020 and 2043 with coupons ranging from 4.53% to 8.82%.

On October 1, 2015, the U.S.$9,800 LPSCo Water System IDA bonds were fully repaid.

As of December 31, 2016, the Company had accrued $25,520 in interest expense (2015 - $25,161). Interest expense on the long-term debt in 2016 was $87,143 (2015 - $72,213).

Principal payments due in the next five years and thereafter are as follows:

2017	2018	2019	2020	2021	Thereafter	Total
$ 1,871,864	$ 461,058	$ 284,243	$ 147,264	$ 157,626	$ 979,210	$ 3,901,265

Short-term obligations of $1,861,788 that were refinanced on a long-term basis before the issuance of the financial statements are presented as long-term debt.

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

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to substantially all of its employees. The Company's contributions for 2016 were $5,223 (2015 - $4,132).

In conjunction with previous utility acquisitions, the Company assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee's years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as of December 31:

	Pension benefits		OPEB	
	2016	2015	**2016**	2015
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 269,382**	$ 241,963	**$ 76,565**	$ 68,257
Projected benefit obligation assumed from business combination	**63,811**	—	**9,749**	—
Modifications to pension plan	**(2,754)**	(4,995)	**(1,235)**	—
Service cost	**8,435**	6,663	**2,916**	3,093
Interest cost	**13,029**	9,642	**3,525**	2,914
Actuarial (gain) loss	**6,773**	(16,098)	**(2,870)**	(8,466)
Contributions from retirees	**—**	—	**547**	412
Benefits paid	**(15,845)**	(13,024)	**(3,230)**	(2,447)
(Gain) loss on foreign exchange	**(10,897)**	45,231	**(2,870)**	12,802
Projected benefit obligation, end of year	**$ 331,934**	$ 269,382	**$ 83,097**	$ 76,565
Change in plan assets				
Fair value of plan assets, beginning of year	**176,172**	156,990	**18,149**	14,295
Plan assets acquired in business combination	**44,258**	—	**10,563**	—
Actual return (loss) on plan assets	**17,221**	(5,657)	**1,854**	20
Employer contributions	**21,775**	7,975	**2,317**	3,028
Benefits paid	**(15,845)**	(12,589)	**(2,683)**	(2,036)
Gain (loss) on foreign exchange	**(7,212)**	29,453	**(1,061)**	2,842
Fair value of plan assets, end of year	**$ 236,369**	$ 176,172	**$ 29,139**	$ 18,149
Unfunded status	**$ (95,565)**	$ (93,210)	**$ (53,958)**	$ (58,416)
Amounts recognized in the consolidated balance sheets consists of:				
Current liabilities	**(436)**	(470)	**(1,242)**	(1,062)
Non-current liabilities	**(95,129)**	(92,740)	**(52,716)**	(57,354)
Net amount recognized	**$ (95,565)**	$ (93,210)	**$ (53,958)**	$ (58,416)

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

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

The accumulated benefit obligation for the pension plans was $317,025 and $251,932 as of December 31, 2016 and 2015, respectively.

During 2016 and 2015, the Company permanently froze the accrual of retirement benefits for participants under existing plans. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The plan amendments resulted in a decrease to the projected benefit obligation of U.S.$2,217 (2015 -$3,941) which is recorded as a prior service credit in OCI. In conjunction with the plan amendments, the assets and projected benefit obligations of amended plans were revalued at the closest month-end date which resulted in an actuarial loss of U.S.$8,204 (2015 gain - U.S.$1,998) recorded in OCI.

Change in AOCI (before tax)	Pension		OPEB	
	Actuarial losses (gains)	Past service gains	Actuarial losses (gains)	Past service gains
Balance, January 1, 2015	$ 29,314	$ (563)	$ 5,896	$ —
Additions to AOCI	1,505	(4,864)	(7,554)	—
Amortization in current period	(1,358)	457	(680)	—
Balance at December 31, 2015	$ 29,461	$ (4,970)	$ (2,338)	$ —
Additions to AOCI	4,479	(2,754)	(3,242)	(1,235)
Amortization in current period	(1,965)	765	(80)	347
Balance at December 31, 2016	$ 31,975	$ (6,959)	$ (5,660)	$ (888)
Expected amortization in 2017	$ (1,437)	$ 836	$ 545	$ —

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2016 and 2015 were as follows:

	Pension benefits		OPEB	
	2016	2015	**2016**	2015
Discount rate	**4.16%**	3.71%	**4.23%**	3.82%
Expected return on assets	**6.41%**	6.44%	**5.50%**	5.50%
Rate of compensation increase	**3.00%**	3.01%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.50%**	7.00%
Age 65 and after			**6.50%**	7.00%
Assumed Ultimate Medical Inflation Rate			**4.75%**	5.00%
Year in which Ultimate Rate is reached			**2023**	2019

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

10. Pension and other post-employment benefits (continued)

(b) Assumptions (continued)

Weighted average assumptions used to determine net benefit obligation for 2016 and 2015 were as follows:

	Pension benefits		OPEB	
	2016	**2015**	**2016**	**2015**
Discount rate	**3.95%**	4.16%	**4.04%**	4.23%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.50%
Age 65 and after			**6.25%**	6.50%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2023**	2023

The mortality assumption for December 31, 2016 was updated to the projected generationally scale MP-2016, adjusted to reflect the ultimate improvement rates in the 2016 Social Security Administration intermediate assumptions.

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

The effect of a one percent change in the assumed health care cost trend rate ("HCCTR") for 2016 is as follows:

	2016
Effect of a 1 percentage point increase in the HCCTR on:	
Year-end benefit obligation	$ 11,343
Total service and interest cost	1,019
Effect of a 1 percentage point decrease in the HCCTR on:	
Year-end benefit obligation	$ (9,430)
Total service and interest cost	(846)

(c) Benefit costs

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

	Pension benefits		OPEB	
	2016	**2015**	**2016**	**2015**
Service cost	**$ 8,435**	$ 6,663	**$ 2,916**	$ 3,093
Interest cost	**13,029**	9,642	**3,525**	2,914
Expected return on plan assets	**(14,854)**	(11,989)	**(1,265)**	(713)
Amortization of net actuarial loss	**1,965**	1,398	**80**	510
Amortization of prior service credits	**(765)**	(471)	**(347)**	—
Net benefit cost	**$ 7,810**	$ 5,243	**$ 4,909**	$ 5,804

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

10. Pension and other post-employment benefits (continued)

(d) Plan assets

The Company's investment strategy for its pension and post-employment plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

Asset Class	Target (%)	Range (%)
Equity securities	72%	49% - 79%
Debt securities	28%	21% - 51%
Other	—%	—%

The fair values of investments as of December 31, 2016, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	192,018	72%
Debt securities	72,664	28%
Other	825	—%

As of December 31, 2016, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $18,159 to its pension plans and $4,295 to its post-employment benefit plans in 2017.

The expected benefit payments over the next ten years are as follows:

	2017	2018	2019	2020	2021	2022-2026
Pension plan	$ 20,650	$ 17,486	$ 18,291	$ 19,111	$ 20,139	$ 116,146
OPEB	3,692	3,818	4,033	4,548	4,833	27,708

11. Mandatorily redeemable Series C preferred shares

APUC has 100 redeemable Series C preferred shares issued and outstanding. Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule indexed in proportion to the increase in CPI over the term of the shares. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

As these shares are mandatorily redeemable for cash, they are classified as liabilities in the consolidated financial statements. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

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

11. Mandatorily redeemable Series C preferred shares (continued)

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are:

	2017	$ 908
	2018	1,068
	2019	1,282
	2020	1,344
	2021	1,364
Thereafter to 2031		17,150
Redemption amount		5,340
		28,456
Less amounts representing interest		(9,996)
		18,460
Less current portion		(908)
		$ 17,552

12. Other assets

Other assets consist of the following:

	2016	2015
Supplies and consumables inventory	**$ 15,568**	$ 14,977
Income tax receivable	**2,951**	3,096
Deferred financing costs	**10,198**	3,211
Other	**6,136**	4,306
	34,853	25,590
Less current portion	**(18,519)**	(18,073)
	$ 16,334	$ 7,517

13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	2016	2015
Advances in aid of construction (a)	**$ 105,191**	$ 92,285
Environmental remediation obligation (b)	**63,378**	71,529
Asset retirement obligations (c)	**24,822**	17,799
Customer deposits (d)	**14,881**	15,074
Deferred income (e)	**—**	13,682
Deferred credits (f)	**44,544**	25,544
Other	**22,790**	23,843
	275,606	259,756
Less current portion	**(43,157)**	(36,621)
	$ 232,449	$ 223,135

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

13. Other long-term liabilities and deferred credits (continued)

(a) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development.

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 10 to 40 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2016, $23,986 (2015 - $4,637) was transferred from advances in aid of construction to contributions in aid of construction.

(b) Environmental remediation obligation

Prior to their acquisition by the Company, EnergyNorth Gas, Granite State Electric and New England Gas Systems were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $76,853 (2015 - $78,495) which at discount rates ranging from 3.9% to 4.7% represents the recorded accrual of $63,378 as of December 31, 2016 (2015 - $71,529). Approximately $27,976 is expected to be incurred over the next three years with the balance of cash flows to be incurred over the following 28 years.

Changes in the environmental remediation obligation are as follows:

	2016	2015
Opening Balance	**$ 71,529**	$ 70,072
Remediation activities	**(1,389)**	(10,621)
Accretion	**2,464**	2,147
Changes in cash flow estimates	**2,088**	3,171
Revision in assumptions	**(9,101)**	(5,843)
Foreign exchange rate adjustment	**(2,213)**	12,603
Closing Balance	**$ 63,378**	$ 71,529

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2016, the Company has reflected a regulatory asset of $104,160 (2015 - $116,747) for the MGP and related sites (note 7(a)).

(c) Asset retirement obligations

Asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (cleanup of natural gas and PCB contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or sections of gas main are removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities. During the year, APUC recorded additional asset retirement obligations for renewable generation facilities being constructed of $393 (2015 - $506), changes in estimates of $1,022 (2015 - $nil) and accretion expense of $1,055 (2015 - $854).

(d) Customer deposits

Customer deposits result from the Company's obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

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

13. Other long-term liabilities and deferred credits (continued)

(e) Deferred income

Proceeds received from insurance in advance of repairs, rates collected subject to dispute and other similar proceeds are deferred until they are virtually certain of being realized.

(f) Deferred credits

Deferred credits include unresolved contingent consideration related to prior acquisitions which are expected to be paid and deferred tax credits (note 20).

14. 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		357,694
Amortization of deferred financing costs		925
Carrying value at December 31, 2016	$	358,619
Face value at December 31, 2016	$	382,950

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

The convertible debentures were sold on an instalment basis at a price of $1,000 principal amount of debenture, of which $333 was received on closing of the debenture offering and the remaining $667 (the "Final Instalment") is receivable on a date ("Final Instalment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial instalment were $382,950. The Company incurred deferred financing costs of $25,255, 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 consolidated balance sheets as settlement in cash is not expected to occur within 12 months. The convertible debentures mature on March 31, 2026 and bear interest at an annual rate of 5% per $1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate will be 0%. The interest expense recorded is $48,205 (2015 - $nil).

The Final Instalment Date took place subsequent to year-end, on February 2, 2017. The proceeds received from the Final instalment were $767,050, before financing costs of $23,000. As the Final Instalment Date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017.

APUC may issue up to 108,490,566 common shares upon conversion of the outstanding debentures. As at March 1, 2017, a total of 107,517,895 common shares of the company were issued, representing conversion into common shares of more than 99.1% of the convertible debentures.

After the Final Instalment Date, any debentures not converted into common shares 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.

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

15. Shareholders' capital

(a) Common shares

Number of common shares:

	2016	2015
Common shares, beginning of year	**255,869,419**	238,149,468
Public offering (i) and subscription receipts (ii)	**12,938,457**	14,355,000
Dividend reinvestment plan (iii)	**2,322,618**	3,230,697
Exercise of share-based awards (c)	**2,956,524**	134,254
Common shares, end of year	**274,087,018**	255,869,419

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the "Board"); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC, subject to the rights of any shares having priority over the common shares.

The Company has a shareholders' rights plan (the "Rights Plan") which expires in 2019. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(i) Public offering

In December 2015, APUC issued 14,355,000 common shares at $10.45 per share pursuant to a public offering for proceeds of $150,010 before issuance costs of $6,735 or $5,023 net of taxes.

(ii) Subscription receipts

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

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

(iii) Dividend reinvestment plan

The Company has a common shareholder dividend reinvestment plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional common shares acquired through the reinvestment of cash dividends are purchased in the open market or are issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 823,738 common shares under the dividend reinvestment plan.

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

15. Shareholders' capital (Continued)

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board.

The Company has the following Series A and Series D preferred shares issued and outstanding as at December 31, 2016 and 2015:

Preferred shares	Number of shares	Price per share	Carrying amount
Series A	**4,800,000**	**$ 25**	**$ 116,546**
Series D	**4,000,000**	**$ 25**	**97,259**
			$ 213,805

The holders of Series A and Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of $1.125 and $1.25 per share, respectively, for each year up to, but excluding December 31, 2018 and March 31, 2019, respectively. The Series A and Series D dividend rate will reset on those dates and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94% and 3.28%, respectively. The Series A and Series D preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter.

The holders of Series A and Series D preferred shares have the right to convert their shares into cumulative floating rate preferred shares, Series B and Series E, respectively, subject to certain conditions, on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter. The Series B and Series E preferred shares will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94% and 3.28%, respectively. The holders of Series B and Series E preferred shares will have the right to convert their shares back into Series A and Series D preferred shares on December 31, 2018 and March 31, 2019, respectively and every fifth year thereafter. The Series A, Series B, Series D and Series E preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

The Company has 100 redeemable Series C preferred shares issued and outstanding. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets (note 11).

(c) Share-based compensation

For the year ended December 31, 2016, APUC recorded $5,675 (2015 - $5,330) in total share-based compensation expense detailed as follows:

	2016	2015
Share options	**$ 3,006**	$ 2,742
Directors deferred share units	**683**	404
Employee share purchase	**238**	158
Performance share units	**1,748**	2,026
Total share-based compensation	**$ 5,675**	$ 5,330

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2016, total unrecognized compensation costs related to non-vested options and PSUs were $3,221 and $2,221, respectively, and are expected to be recognized over a period of 1.77 and 1.74 years, respectively.

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

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan

The Company's share option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 8% of the number of shares outstanding at the time the options are granted.

The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money Amount" being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

In 2016, the shareholders of APUC approved a provision whereby in the event that the Company restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Board (or the compensation committee of the Board ("Compensation Committee")) in accordance with the terms of the Company's clawback policy.

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. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

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

	2016	2015
Risk-free interest rate	**0.9%**	1.3%
Expected volatility	**23%**	38%
Expected dividend yield	**4.5%**	4.0%
Expected life	**5.50 years**	8 years
Weighted average grant date fair value per option	**$ 1.26**	$ 2.45

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

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

Share option activity during the years is as follows:

	Number of awards		Weighted average exercise price	Weighted average remaining contractual term (years)		Aggregate intrinsic value
Balance at January 1, 2015	5,537,127	$	6.09	4.96	$	19,648
Granted	1,627,525		9.75	8.00		
Balance at December 31, 2015	7,164,652	$	6.92	4.74	$	28,561
Granted	2,596,025		10.85	8.00		
Exercised	(3,715,663)		5.25	2.06		20,790
Balance at December 31, 2016	6,045,014	$	9.64	6.27	$	10,595
Exercisable at December 31, 2016	2,120,539	$	8.36	5.16	$	6,420

(ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match (a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and (b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Common shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the common shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2016, a total of 144,264 common shares (2015 - 111,355) were issued to employees under the ESPP.

(iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2016, 224,663 (2015 - 157,471) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU Plan shall not exceed 1,000,000 common shares.

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

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance share units

The Company offers a PSU plan to its employees as part of the Company's long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 0% to 197.5% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

Compensation expense associated with PSUs is recognized rateably over the performance period and assumes that performance goals will be achieved at 100%. If goals met differ, compensation cost recognized is adjusted to reflect the performance conditions achieved.

A summary of the PSUs follows:

	Number of awards	Weighted average grant-date fair value	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2015	440,086	$ 6.57	1.81	$ 4,242
Granted, including dividends	212,250	9.72	2.62	—
Exercised	(41,131)	6.86	—	381
Forfeited	(47,089)	8.30	—	—
Balance at December 31, 2015	564,116	$ 7.59	1.63	$ 6,155
Granted, including dividends	219,315	11.62	2.00	—
Exercised	(181,875)	8.29	—	2,115
Forfeited	(22,568)	9.64	—	—
Balance at December 31, 2016	578,988	$ 9.82	1.74	$ 6,595
Exercisable at December 31, 2016	215,790	$ 8.22	—	$ 2,458

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

16. 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	(61,029)	34,308	213	1,648	(24,860)
Amounts reclassified	—	(7,554)	—	604	(6,950)
Net current period OCI	$ (61,029)	$ 26,754	$ 213	$ 2,252	$ (31,810)
Balance, December 31, 2016	$ 200,328	$ 66,083	$ 141	$ (11,625)	$ 254,927

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.

17. 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 year were as follows:

	2016		2015	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 149,158**	**$ 0.5452**	$ 124,831	$ 0.4867
Series A preferred shares	**$ 5,400**	**$ 1.1250**	$ 5,400	$ 1.1250
Series D preferred shares	**$ 5,000**	**$ 1.2500**	$ 5,000	$ 1.2500

18. Related party transactions

Emera Inc.

A member of the Board of APUC is an executive at Emera. During 2016, the Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro subsidiaries of Emera, amounting to U.S.$10,185 (2015 - U.S.$6,658). During 2016, Liberty Utilities purchased natural gas amounting to U.S. $3,939 (2015 - U.S.$2,292) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction. On May 13, 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The total cost of the contract is estimated at $8,797 and is expected to be completed in 2017. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $680 to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S.$757 included in accruals in 2016 (2015 - U.S.$491) related to these transactions at the end of the year.

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

18. Related party transactions (continued)

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 $3,313 (2015 - $2,021) during the year.

Trafalgar

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

In 2003 and 2004, the Company reimbursed the Related Entity $1,000 of the approximately $2,000 in third-party legal fees it had initially funded and APUC agreed to fund future legal fees and other liabilities. It was agreed that any net proceeds from the litigation and bankruptcy proceedings would be shared proportionally to the quantum of net legal costs funded by each party.

On June 30, 2016, the Company received U.S. $10,083 in proceeds from the settlement of this matter and, subsequent to quarter-end, paid U.S. $2,900 to the Related Entity as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6,600 was recorded in the second quarter of 2016.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2017.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

19. Non-controlling interests and Redeemable non-controlling interest

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

	2016	2015
HLBV and other adjustments attributable to:		
Non-controlling interest -Class A partnership units (i)	**$ (35,451)**	$ (30,371)
Non-controlling interest -redeemable Class A partnership units (i)	**(4,952)**	(3,571)
Other net earnings attributable to non-controlling interests	**1,853**	1,966
Net effect of non-controlling interests	**$ (38,550)**	$ (31,976)

(i) The non-controlling Class A membership equity investors ("Class A partnership units") in the Company's U.S. wind power and solar power generating facilities are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(q).

As of December 31, 2016, non-controlling interests of $562,358 (2015 - $356,800) includes Class A partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $561,308 (2015 - $355,842) and other non-controlling interests of $1,050 (2015 - $958).

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The redeemable non-controlling interests in subsidiaries balance is determined using the hypothetical liquidation at book value method subsequent to initial recognition, however, if the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2016.

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

19. Non-controlling interests and Redeemable non-controlling interest (continued)

Changes in redeemable non-controlling interest are as follows:

	2016	2015
Opening balance	$ 25,751	$ 12,146
Net loss attributable to redeemable non-controlling interest	(4,952)	(3,571)
Contributions from redeemable non-controlling interests (notes 3(b) and 3(h))	10,171	15,222
Dividends declared and distributions to redeemable non-controlling interest	(590)	(309)
Foreign exchange	(946)	2,263
Closing balance	$ 29,434	$ 25,751

20. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2015 - 26.5%). The differences are as follows:

	2016	2015
Expected income tax expense at Canadian statutory rate	$ 34,317	$ 34,516
Increase (decrease) resulting from:		
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	(11,363)	(5,943)
Non-controlling interests share of income	13,973	12,511
Allowance for equity funds used during construction	(1,100)	(935)
Capital gain rate differential	(3,612)	(961)
Non-deductible acquisition costs	1,996	365
Change in valuation allowance	2,841	109
Recognition of deferred credit	—	(2,448)
Adjustment relating to prior periods	(711)	2,431
CRA Settlement	—	2,709
Other	795	1,359
Income tax expense	$ 37,136	$ 43,713

For the years ended December 31, 2016 and 2015, earnings from continuing operations before income taxes consist of the following:

	2016	2015
Canadian operations	$ 29	$ 28,481
U.S. operations	129,481	101,768
	$ 129,510	$ 130,249

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

20. Income taxes (continued)

Income tax expense (recovery) attributable to income (loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2016			
Canada	**$ 7,533**	**$ (10,501)**	**$ (2,968)**
United States	**928**	**39,176**	**40,104**
	$ 8,461	**$ 28,675**	**$ 37,136**
Year ended December 31, 2015			
Canada	$ 5,272	$ 1,959	$ 7,231
United States	2,038	34,444	36,482
	$ 7,310	$ 36,403	$ 43,713

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities as of December 31, 2016 and 2015 are presented below:

	2016	2015
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 458,508**	$ 399,754
Pension and OPEB	**57,751**	57,969
Acquisition-related costs	**4,773**	6,035
Environmental obligation	**25,683**	28,230
Reserves and other non-deductible costs	**11,390**	2,503
Regulatory liabilities	**76,315**	68,166
Other	**15,302**	5,404
Total deferred income tax assets	**649,722**	568,061
Less valuation allowance	**(21,656)**	(17,478)
Total deferred tax assets	**628,066**	550,583
Deferred tax liabilities:		
Property, plant and equipment	**(562,124)**	(444,385)
Intangible assets	**(9,197)**	(2,760)
Outside basis in partnership	**(187,717)**	(164,692)
Regulatory accounts	**(108,506)**	(96,436)
Financial derivatives	**(17,649)**	—
Other	**(1,007)**	—
Total deferred tax liabilities	**(886,200)**	(708,273)
Net deferred tax liabilities	**$ (258,134)**	$ (157,690)
Consolidated Balance Sheets Classification:		
Deferred tax assets	**$ 30,005**	$ 18,109
Deferred tax liabilities	**(288,139)**	$ (175,799)
Net deferred tax liabilities	**$ (258,134)**	$ (157,690)

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

20. Income taxes (continued)

The valuation allowance for deferred tax assets as at December 31, 2016 was $21,656 (2015 - $17,478). The valuation allowance primarily relates to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

As of December 31, 2016, the Company had non-capital losses carried forward available to reduce future year's taxable income, which expire as follows:

Year of expiry		Non-capital loss carryforwards
2020 and onwards	$	1,116,631

On June 26, 2015, the Company entered into an agreement with the Canada Revenue Agency ("CRA") regarding CRA's proposal to reassess APUC's 2009 through 2013 income tax filings in relation to a unit exchange transaction that occurred on October 27, 2009. The agreement resulted in a $16,042 reduction in the APUC's deferred tax assets and a proportional reduction of $13,333 in its deferred credits (note 13(f)). Consequently, the Company's results for 2015 reflect a $2,709 net non-cash charge to deferred income tax expense.

The Company has provided for deferred income taxes for the estimated tax cost of distributed earnings of its subsidiaries. Deferred income taxes have not been provided on approximately $88,306 of undistributed earnings of certain foreign subsidiaries, as the Company has concluded that such earnings are indefinitely reinvested and should not give rise to additional tax liabilities. A determination of the amount of the unrecognized tax liability relating to the remittance of such undistributed earnings is not practicable.

21. 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 (note 15 (a)(ii)). 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 are as follows:

		2016		2015
Net earnings attributable to shareholders of APUC	**$**	**130,924**	$	117,480
Series A Preferred shares dividend		**5,400**		5,400
Series D Preferred shares dividend		**5,000**		5,000
Net earnings attributable to common shareholders of APUC	**$**	**120,524**	$	107,080
Discontinued operations		**—**		(1,032)
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	**$**	**120,524**	$	108,112
Weighted average number of shares				
Basic		**271,832,430**		253,172,088
Effect of dilutive securities		**2,244,602**		3,344,632
Diluted		**274,077,032**		256,516,720

The shares potentially issuable as a result of 1,665,131 share options (2015 - 1,627,525) are excluded from this calculation as they are anti-dilutive.

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

21. Basic and diluted net earnings per share (continued)

The convertible debentures (note 14) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. As the Final Instalment Date occurred subsequent to year-end, on February 2, 2017, the contingency had not been met on December 31, 2016 and as such, the shares issuable upon conversion of the convertible debentures are not included in diluted earnings per share above. Beginning February 2, 2017, assuming full payment of the final instalment, 108,490,566 common shares will be included as a component of the Company's diluted EPS. As at March 1, 2017, a total of 107,517,895 common shares of the company were issued, representing conversion into common shares of more than 99.1% of the convertible debentures.

22. Segmented information

APUC's operations are organized across two primary North American business units consisting of the Renewable Generation Group and the Liberty Utilities Group.

The Renewable Generation Group ("Renewable Generation Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group ("Liberty Utilities Group") owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

As at December 31, 2016, APUC has three reporting segments: Generation, Transmission and Distribution.The Transmission segment is not 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.

	Year ended December 31, 2016			
	Generation	**Distribution**	**Corporate**	**Total**
Revenue	$ 265,949	$ 830,069	$ —	$ 1,096,018
Fuel, power and water purchased	21,260	274,055	—	295,315
Net revenue	244,689	556,014	—	800,703
Operating expenses	72,346	258,664	1,991	333,001
Administrative expenses	19,656	26,272	421	46,349
Depreciation and amortization	80,094	102,657	4,148	186,899
Gain on foreign exchange	—	—	(436)	(436)
Operating income (loss) from continuing operations	72,593	168,421	(6,124)	234,890
Interest expense	21,847	50,616	59,129	131,592
Interest, dividend, equity and other income	32	(5,125)	(5,480)	(10,573)
Other expenses (gain)	(14,403)	(18,119)	16,883	(15,639)
Earnings (loss) before income taxes	$ 65,117	$ 141,049	$ (76,656)	$ 129,510
Property, plant and equipment	$2,455,336	$2,345,436	$ 89,174	$ 4,889,946
Equity-method investees	59,021	914	4,484	64,419
Total assets	2,771,651	5,343,023	134,786	8,249,460
Capital expenditures	141,420	235,744	28,579	405,743

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

22. Segmented information (continued)

	Year ended December 31, 2015			
	Generation	Distribution	Corporate	Total
Revenue	$ 244,751	$ 783,104	$ —	$1,027,855
Fuel and power purchased	27,990	348,883	—	376,873
Net revenue	216,761	434,221	—	650,982
Operating expenses	63,601	214,064	1,741	279,406
Administrative expenses	10,822	20,725	8,283	39,830
Depreciation and amortization	67,293	82,513	—	149,806
Gain on foreign exchange	—	—	(2,631)	(2,631)
	75,045	116,919	(7,393)	184,571
Interest expense	29,395	34,971	1,627	65,993
Interest, dividend and other income	(1,154)	(3,974)	(3,967)	(9,095)
Other expense (gain)	(5,623)	391	2,656	(2,576)
Earnings (loss) before income taxes	$ 52,427	$ 85,531	$ (7,709)	$ 130,249
Property, plant and equipment	$1,899,103	$1,890,353	$ 87,714	$3,877,170
Equity-method investees	44,638	769	7,066	52,473
Total assets	2,345,905	2,508,267	137,553	4,991,725
Capital expenditures	55,992	119,967	28,236	204,195

The majority of non-regulated energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2016 or 2015: Ontario Hydro 12% (2015 - 9%); Hydro Québec 11% (2015 - 13%); Manitoba Hydro 12% (2015 - 13%); PJM 13% (2015 - 14%); and ComEd 10% (2015 - 11%). The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations.

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2016	2015
Revenue		
Canada	**$ 100,403**	$ 86,977
United States	**995,615**	940,878
	$ 1,096,018	$ 1,027,855
Property, plant and equipment		
Canada	**$ 558,271**	$ 592,598
United States	**4,331,675**	3,284,572
	$ 4,889,946	$ 3,877,170
Intangible assets		
Canada	**$ 36,611**	$ 40,186
United States	**28,378**	34,291
	$ 64,989	$ 74,477

Revenue is attributed to the two countries based on the location of the underlying generating and utility facilities.

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

23. 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. Accruals for any contingencies related to these items are recorded in the consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 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 (i)	$ 63,330	$ 36,622	$ 37,398	$ 38,822	$ 38,822	$ —	$ 214,994
Gas supply and service agreements (ii)	62,179	45,468	37,407	31,636	17,400	64,284	258,374
Service agreements	41,446	42,252	42,508	45,178	46,019	503,671	721,074
Capital projects	66,696	19,538	69	69	69	17	86,458
Operating leases	7,342	6,851	6,519	6,403	6,480	123,604	157,199
Total	$240,993	$150,731	$123,901	$122,108	$108,790	$691,576	$1,438,099

(i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above are based on market prices as of December 31, 2016. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

(ii) Gas supply and service agreements: APUC's gas distribution facilities and thermal generation facilities have commitments to purchase physical quantities of natural gas under contracts for purposes of load serving requirements and of generating power.

24. Non-cash operating items

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

	2016	2015
Accounts receivable	**$ 6,612**	$ 6,715
Natural gas in storage	**6,877**	3,049
Supplies and consumable inventory	**692**	(2,968)
Income taxes receivable	**145**	(2,529)
Prepaid expenses	**(6,161)**	(7,833)
Accounts payable	**24,524**	(18,261)
Accrued liabilities	**(9,454)**	(28,495)
Current income tax liability	**(4,552)**	1,820
Net regulatory assets and liabilities	**(14,979)**	37,353
	$ 3,704	$ (11,149)

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

25. Financial instruments

(a) Fair value of financial instruments

2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 38,183	$ 47,933	$ —	$ 47,933	$ —
Derivative instruments [1]:					
Energy contracts designated as a cash flow hedge	84,554	84,554	—	—	84,554
Interest rate swap designated as a hedge	48,093	48,093	—	48,093	—
Currency forward contract not designated as a hedge	17,864	17,864	—	17,864	—
Commodity contracts for regulated operations	359	359	—	359	—
Total derivative instruments	150,870	150,870	—	66,316	84,554
Total financial assets	$ 189,053	$ 198,803	$ —	$ 114,249	$ 84,554
Long-term debt	$ 3,913,415	$ 3,999,266	$ 517,637	$ 3,481,629	$ —
Convertible debentures	358,619	455,975	455,975	—	—
Preferred shares, Series C	18,460	18,613	—	18,613	—
Derivative instruments [1]:					
Cross-currency swap designated as a net investment hedge	95,404	95,404	—	95,404	—
Interest rate swap designated as a hedge	13,385	13,385	—	13,385	—
Commodity contracts for regulated operations	36	36	—	36	—
Total derivative instruments	108,825	108,825	—	108,825	—
Total financial liabilities	$ 4,399,319	$ 4,582,679	$ 973,612	$ 3,609,067	$ —

(1) Balance of $314 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

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

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2015	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 119,383	$ 126,468	$ —	$ 126,468	$ —
Derivative 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 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 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	—
Interest rate swaps not designated as a hedge	1,918	1,918	—	1,918	—
Commodity contracts for regulated operations	1,676	1,676	—	1,676	—
Total derivative instruments	115,258	115,258	—	114,812	446
Total financial liabilities	$1,620,580	$1,679,907	$ 511,829	$1,167,632	$ 446

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

25. 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 December 31, 2016 and 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 $24.44 to $105.03 with a weighted average of $37.36 as of December 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 25(b)(ii) and 25(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 years ended December 31, 2016 and 2015.

(b) Derivative instruments

Derivative instruments are recognized on the 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	384,999
Gas options	844,167
	1,229,166

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 consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7(c)). 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.

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

25. 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 consolidated balance sheets:

		2016		2015
Regulatory assets:				
Gas swap contracts	U.S. $	—	U.S. $	1,058
Gas option contracts	U.S. $	27	U.S. $	154
Regulatory liabilities:				
Gas swap contracts	U.S. $	175	U.S. $	3
Gas option contracts	U.S. $	92	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 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)
686,340	December 2022	U.S. $	42.81	PJM Western HUB
2,930,009	December 2022	U.S. $	30.25	NI HUB
3,663,549	December 2027	U.S. $	36.46	ERCOT North HUB

On October 25, 2016, the Company entered into forward contracts to purchase U.S.$250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S.$250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S.$500,000 bonds in relation to the acquisition of Empire (note 9(d)). The change in fair value resulted in a gain of U.S.$35,815 for the year ended December 31, 2016.

The Company is party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a loss of $3,726 for the year ended December 31, 2016 (2015 - loss of $4,974), which is recorded in OCI.

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

		2016		2015
Effective portion of cash flow hedge, gain	$	34,355	$	21,932
Amortization of cash flow hedge		(47)		(36)
Gain reclassified from AOCI		(7,554)		(5,731)
OCI attributable to shareholders of APUC	$	26,754	$	16,165

The Company expects $10,024 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.

25. 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 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 Renewable Generation Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Renewable 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 year ended December 31, 2016 (2015 - nil) was recorded in OCI.

Concurrent with its $150,000, $200,000 and $300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, 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. A gain of $2,189 (2015 - loss of $68,195) was recorded in OCI in 2016 for the December 2012 and January 2014 swaps.

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

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 25(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. 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 8(f)). This risk was mitigated through the use of currency forward contracts to sell U.S. $38,400 for $47,225 between July 29, 2016 and September 29, 2016. As of December 31, 2016, these instruments had settled. This currency forward contract was not accounted for as a hedge.

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

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to foreign exchange fluctuations related to the expected acquisition of the Empire shares denominated in U.S dollar (note 3(a)). This risk is mitigated through the conversion to U.S. dollars of $359,950 from the proceeds received on the initial instalment of convertible unsecured subordinated debentures (note 14) and the use of a currency forward contract to buy an amount of U.S. $567,665 for $744,050 on January 31, 2017. As of December 31, 2016, the estimated fair value of the instrument was an asset of $17,864. This currency forward contract was not accounted for as a hedge.

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

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

	2016	2015
Change in unrealized loss (gain) on derivative financial instruments:		
Interest rate swaps	$ —	$ (1,383)
Energy derivative contracts	(426)	886
Currency forward contract	(19,810)	1,918
Total change in unrealized loss (gain) on derivative financial instruments	$ (20,236)	$ 1,421
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	—	1,498
Energy derivative contracts	951	(579)
Currency forward contract	(1,371)	—
Total realized loss (gain) on derivative financial instruments	$ (420)	$ 919
Loss (gain) on derivative financial instruments not accounted for as hedges	(20,656)	2,340
Ineffective portion of derivative financial instruments accounted for as hedges	1,518	(2,610)
	$ (19,138)	$ (270)
Amounts recognized in the consolidated statements of operations consist of:		
Gain on derivative financial instruments	$ (15,849)	$ (2,188)
Loss (gain) on foreign exchange	$ (3,289)	$ 1,918
	$ (19,138)	$ (270)

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

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

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

25. Financial instruments (continued)

(c) Risk management (continued)

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders all of which have a credit rating of A or better. The Company does not consider the risk associated with the Renewable Generation Group accounts receivable to be significant as over 80% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of U.S.$100,417 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2016, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2016	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 16,874	$ 1,578,704
Accounts receivable	14,571	135,660
Allowance for doubtful accounts	—	(5,261)
Notes receivable	31,406	5,048
	$ 62,851	$ 1,714,151

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2016, in addition to cash on hand of $110,417 the Company had $295,915 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

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

25. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk (continued)

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long-term debt obligations	$1,871,864	$ 745,301	$ 304,890	$ 979,210	$3,901,265
Convertible Debentures	—	—	—	358,619	358,619
Advances in aid of construction	3,140	—	—	102,051	105,191
Interest on long-term debt	194,831	152,976	110,718	347,700	806,225
Purchase obligations	398,910	—	—	—	398,910
Environmental obligation	4,043	23,933	7,123	41,754	76,853
Derivative financial instruments:					
Cross-currency swap	4,144	7,660	49,358	34,242	95,404
Interest rate swaps	—	13,385	—	—	13,385
Energy derivative and commodity contracts	34	2	—	—	36
Other obligations	32,624	—	—	47,212	79,836
Total obligations	$2,509,590	$ 943,257	$ 472,089	$1,910,788	$5,835,724

26. Comparative figures

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

CORPORATE INFORMATION

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Christopher Ball – Executive Vice President, Corpfinance International Ltd.
Chris Jarratt – Vice Chair, Algonquin Power & Utilities Corp.
D. Randy Laney – Former Chairman of the Board, The Empire District Electric Company
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
Masheed Saidi – Former Executive VP and Chief Operating Officer, U.S. Transmission, Natural Grid USA
Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy
Melissa Stapleton Barnes – Senior VP, Enterprise Risk Management, and Chief Ethics and Compliance Officer, Eli Lilly and Company
George Steeves – Principal, True North Energy

THE EXECUTIVE TEAM

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Chris Jarratt, Vice Chair
David Bronicheski, Chief Financial Officer
Linda Beairsto, Chief Compliance Officer
Jeff Norman, Chief Development Officer
David Pasieka, Chief Operations Officer, Liberty Utilities Group
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