Section 285.305
General Information Requirements Applicable to all Utilities Subject to this Part
Utility: Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities

Subpart (l)

ANNUAL REPORT 2015

Algonquin Power & Utilities Corp.

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

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

ALGONQUIN
Power & Utilities Corp.

WWW.ALGONQUINPOWERANDUTILITIES.COM TORONTO STOCK EXCHANGE: AQN

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AQN ACROSS THE UTILITY SPECTRUM

Algonquin Power & Utilities is an integrated utility company participating across the utility spectrum - generation, transmission and distribution.

DISTRIBUTION

The Distribution Business Group owns and operates regulated water, natural gas and electricity distribution utilities in communities across the United States. We own and operate 34 distribution utilities serving more than 560,000 customer connections across 11 states, with our focus on growth achieved through acquisitions and organic growth opportunities currently totaling $2 billion.

EMPIRE – COMPLEMENTARY BUSINESS, FAMILIAR TERRITORY

On February 9, 2016 Algonquin announced the acquisition of the Empire District Electric Company ("Empire"). Empire is a regulated water, gas and electric utility serving 218,000 customers in Missouri, Arkansas, Oklahoma and Kansas. Empire's addition is highly complementary to our business, bringing a mix of generation, transmission and distribution operations to our existing presence in the United States. Empire operates water, gas and electric utilities and overlaps states in which we have an established presence. The addition of Empire to the Algonquin and Liberty Utilities family brings increased scale, management depth and new growth opportunities for our mid-states operations.

"The acquisition of Empire represents a continuation of our disciplined growth strategy. It strengthens and diversifies Algonquin's existing businesses and strategically expands our regulated utility footprint in the mid-west United States. The addition of this large, well run utility to the Algonquin family will support our 10% annual dividend growth target through significant accretion to shareholder cash flows and earnings. Empire's service territories, business lines and corporate culture are highly complementary to Liberty Utilities and we will continue Empire's history of prudently investing in its systems, communities and employees."

Ian Robertson, CEO Algonquin Power & Utilities Corp.

GENERATION

The Generation Business Group generates and sells electricity produced by a diverse portfolio of renewable and clean energy power generation facilities across North America. We have interests in, own and operate more than 36 contracted hydroelectric, wind, solar, and thermal facilities representing over 1,185 MW of installed generating capacity and have future investment opportunities totalling over $1.8 billion in renewable generation to power our growth.

TRANSMISSION

The Transmission Business Group is a regulated transmission utility business that focuses on building and investing in natural gas pipeline and electric transmission opportunities across North America. This group serves to connect our generation and distribution businesses, completing the utility supply chain. The Transmission Business Group is partnering in two natural gas pipeline projects in the north east United States, with an investment opportunity reaching $650 million by 2018.

2015 ACHIEVEMENTS

Algonquin Power & Utilities is led by an experienced executive management team with over 70 years of combined experience in generation, transmission and distribution utilities. We have successfully grown the business for more than 25 years and now boast annual revenues of over $1 billion, total assets of $5 billion and a market capitalization approaching $3 billion.

17.5%
Annual total shareholder return

29%
EBITDA[1] growth

22%
Asset growth

24%
Growth in Adjusted net earnings per share[1]

25%
Growth in Adjusted funds from operations per share[1]

34%
Dividend increase

2015 FINANCIAL HIGHLIGHTS

(in $ millions)

Revenue	2015	2014	2013
Generation Revenue	222.6	202.3	189.7
Distribution Revenue	767.3	717.1	485.2
Other	37.9	22.2	0.4
Total Revenue	**1,027.8**	**941.6**	**675.3**

Adjusted EBITDA[1]	**375.4**	**290.6**	**228.1**

Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations	287.4	206.5	154.9
Per Share	1.15	0.92	0.73
Adjusted Net Earnings	121.5	88.4	59.5
Per Share	0.46	0.37	0.26
Dividends to Shareholders	124.6	82.9	68.3
Per Share	0.49	0.37	0.33

Balance Sheet Data			
Total Assets	4,989.20	4,102.80	3,469.30
Long-Term Liabilities (includes current portion)	1,486.80	1,271.10	1,248.30
Number of Shares Outstanding as of Dec. 31	255,869,419	238,149,468	206,860,592

Renewable energy production (% of long term average)	**93%**	**98%**	**95%**
Utility Connections	**560,000**	**488,000**	**481,400**

[1] **Non-GAAP Financial Measures**

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization", 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 IS TOP OF MIND AT AQN

Safety is foremost in all we do at Algonquin. The common belief that all injuries are preventable is the basis of our "Drive to Zero" recordable or lost time injuries program that is woven into our daily activities.

Over the years, APUC's safety culture has matured, both for the organization as a whole and for our employees. We have come to appreciate that nothing is more important than doing the job safely, and this shows. To keep the momentum going, our team will strive to be the "Best of the Best" through 2016 and beyond, keeping focus and always believing "the most important part of the day is going home to your family in the same condition in which you came to work."

AQN BY THE NUMBERS

21
provinces and states

560,000
utility customers

1,400
employees

11,517
km of gas distribution lines

1,185
MW installed capacity

6,250
km of electricity distribution lines

380
wind turbine generators

3,393
km of water distribution mains

127,572
solar panels

57
hydroelectric generators

14
year average contract length of power purchase agreements

LETTER TO SHAREHOLDERS

Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

Dear Fellow Shareholders,

We are pleased to report a year of solid performance across the Algonquin Power & Utilities Corp. platform; a year which, yet again, confirms our ability to seek out and execute on growth opportunities as one of North America's leading utility companies. Contributions to our financial results were sourced from current operations, newly commissioned generating facilities, and expansion of our distribution utility footprint. The advantages of our parallel foci on non-regulated electric generation and regulated transmission and distribution utility systems bring us opportunities to grow on three fronts and continue to be apparent in our results. We are very pleased to have taken some important new steps to ensure that our growth trajectory extends into the future.

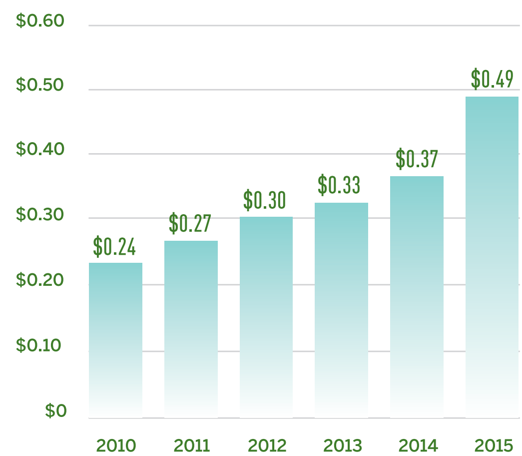
The commitment of every member of the Algonquin Power & Utilities Corp. team to being *"the utility company most admired by our customers, communities and investors for our people, passion and performance"* is the basis for our ability to deliver compelling shareholder returns and an enviable track record of success.

NEW FINANCIAL MILESTONES REACHED, PERFORMANCE CONTINUES

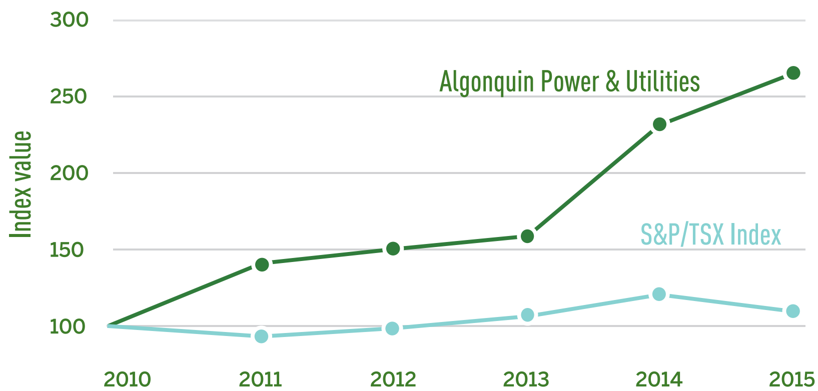
The focus on our vision delivered very strong financial results in 2015, and you will see much evidence of this throughout this report. For the first year in our history, our operations generated over $1 billion in revenues. The alignment of our compensation measures with the achievement of our corporate objectives delivered per share adjusted net earnings growth of 24% and an increase in our adjusted funds from operations of 25% in 2015. With over 80% of our EBITDA generated by our U.S. operations, the appreciation in the value of the U.S. dollar had a positive, material impact on our performance in 2015. But that is only part of the story. Real growth in our generation and distribution business groups also powered our business to record results.

Our persistent focus on providing total shareholder return (TSR) consisting of an attractive dividend yield and capital appreciation founded on increased earnings and cash flows allowed us to post a TSR of 17.5% for 2015, beating the S&P/TSX Composite by nearly 26%. The continuing growth in cash flow and earnings supported the Board of Directors' decision to increase the dividend by 10%, in line with our goal of 10% annual dividend growth and marking our 5th consecutive year of dividend increases. This enviable record secured Algonquin Power & Utilities Corp.'s standing in the S&P/TSX Dividend Aristocrats Index at the beginning of 2016. Our dividend has grown at a compounded rate of over 15% in the past five years. We believe it is our consistent performance and track record of delivering attractive shareholder value that solidifies our position as a "must own" investment holding for all long minded investors.

DIVIDENDS PER SHARE



TOTAL RETURN PERFORMANCE

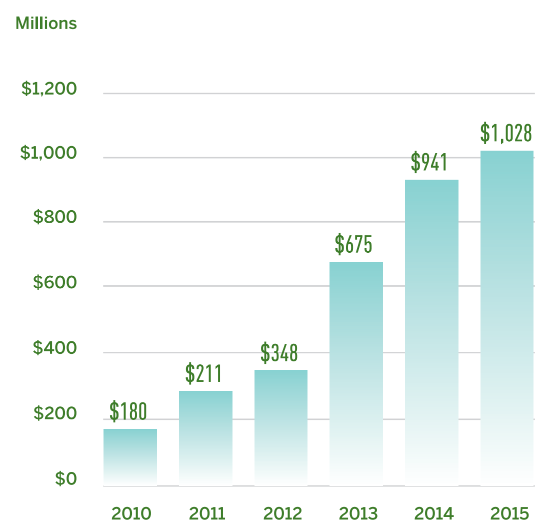


Distribution

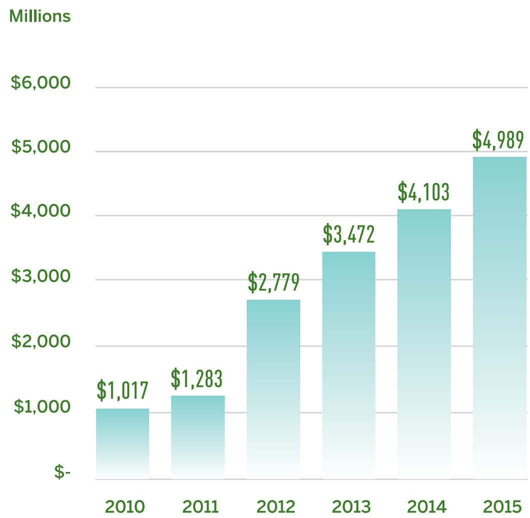
On many fronts it was another successful year for our Distribution Business Group, due primarily to the commitment of our Liberty Utilities team to providing affordable, high quality service to each of our 560,000 customers in the 11 states in which we currently operate. We are continuing on our "March to a Million" customers with the acquisition of the Park Water Company which brought 74,000 new water customers to the Liberty Utilities community. We also finalized several rate proceedings which collectively added over $18.1 million in incremental revenues in 2015 and have added a further $11 million in incremental revenues to date in 2016.

On February 9th, we were pleased to announce an exciting new investment – our agreement for the acquisition of The Empire District Electric Company (Empire). Empire is a Joplin, Missouri-based electric, natural gas, and water utility serving 218,000 customers across the mid-west United States. Our offer being made to Empire's shareholders has been unanimously supported by the Boards of Directors of both companies, and we look forward to securing the necessary regulatory and Empire shareholder approvals by the end of 2016.

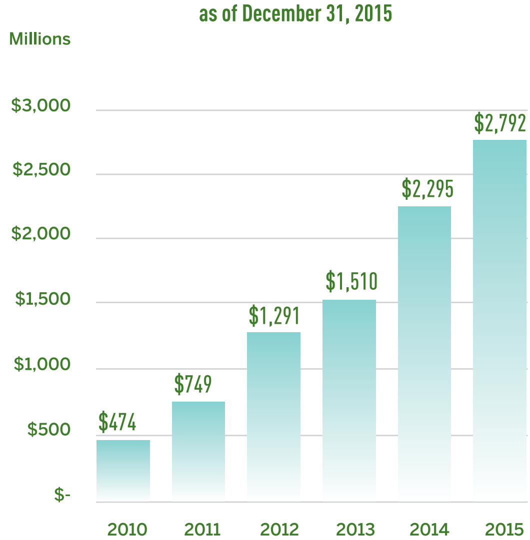
REVENUE



ASSETS



MARKET CAPITALIZATION
as of December 31, 2015



With an aggregate purchase price of $3.4 billion, the Empire acquisition represents our largest growth initiative to date, and the strong cultural alignment between Empire and our current operations and corporate objectives bodes well for this opportunity. The addition of Empire to the Liberty Utilities group brings further scale, geographic diversity, stability and strength and is expected to be accretive to both per-share earnings and cash flow.

Generation

Three new facilities representing 68 MW of solar and wind capacity contributed incremental revenues in 2015 and the long term power purchase agreements of these facilities extended our PPA duration to 14 years. We are continuing our trajectory of growth with more than $650 million in capital investment committed to three new wind and solar projects representing 235 MW of new capacity coming into service in 2016.

On a production basis, the 2015 El Nino effect brought the challenge of widespread lower than average wind and hydrologic conditions. While we obviously cannot control the weather, our facilities achieved an impressive availability level of approximately 97% which demonstrates the capabilities of our operations team to take maximal advantage of available resources.

Transmission

Material changes are under way in the North American energy landscape. As a part of this shift, we see a significant opportunity to help bring renewable generating capacity to customers through investment in new electric transmission lines and in the development of new pipelines to assist domestic natural gas to find routes to market. Energy transmission, both gas and electric, has been a key ingredient in this market transformation.

Having only formed our Transmission Business Group in late 2014, we have made notable progress in identifying over $650 million in growth opportunities in both regulated electric transmission and inter-state natural gas transmission in North America. The regulatory application for our New York to Massachusetts natural gas transmission pipeline was filed in late 2015 with the approval order being expected later this year. In 2015, we also entered into a new joint venture agreement with Kinder Morgan for the development of an interstate pipeline running from Pennsylvania through to New York. We will look to deploy capital into these projects as they advance through their respective phases of development.

A FRESH PERSPECTIVE ON OUR BUSINESS

We've laid out the divisional view of our progress above but we feel it is important to mention new initiatives that were undertaken in 2015 to unearth cross-functional opportunities across our three principal areas – Generation, Distribution, and Transmission. While we will continue to organize ourselves operationally according to these areas, we are challenging our business leaders and our Board to think about our business across these boundaries. We are examining our business from a perspective which aligns closely with the realities of our main markets, to allow us, to the fullest extent possible, to drive new opportunities within the commodity oriented *"strategic verticals"* of *electricity*, *natural gas*, and *water*.

Electricity
The legacy of our company is firmly rooted in the non-utility generation of electricity. Development of renewable energy projects is the foundation on which we have built Algonquin, and we are continuing to capitalize on this core competency to uncover new avenues to growth. Given the societal importance of renewable energy and the bright future for these economically and environmentally compelling forms of generation, our business leaders are being challenged to think across the generation, transmission and distribution boundaries to ensure we capture all available opportunities.

Natural Gas
We also see cross functional development opportunities within the natural gas vertical. We have an initial foothold in this market through our New England natural gas distribution utilities. We believe that the physical constraints on bringing incremental natural gas to these markets are creating the right conditions for success for the two natural gas pipeline projects we are currently pursuing in partnership with Kinder Morgan. The growth in the US domestic gas markets is providing us with new frontiers for capital deployment.

Water
The critical importance of water is demonstrated to us every day, and we take our responsibilities as providers and stewards of our water resources very seriously. We have achieved increased scale in the water utility sector with our recently completed purchase of Park Water, and a number of programs are in place within our water business to complete system improvements, increase water efficiency, and improve customer service levels.

LOOKING TO THE FUTURE

We believe that the prospects for Algonquin Power & Utilities Corp. and its shareholders are indeed very bright. We are off to a strong start to 2016 and major acquisition and development initiatives have positioned us for delivering compelling financial returns to our shareholders.

Our near term capital investment plan represents $7.5 billion in new assets including $4.5 billion in the next 12 months. Our Generation Group is focused on on-time, on-budget delivery of close to $700 million in new renewable generating facilities. Our Distribution Group has committed $3.4 billion for the Empire acquisition and $270 million for continued investment in its existing utility systems. We fully anticipate announcing the addition of incremental development opportunities to our project pipeline through 2016.

FINAL THOUGHTS

We are fortunate to have a community of dedicated employees that has grown both in number and in the level of expertise they bring to their work every day. Durable relationships are forged by our employees with suppliers, customers, landowners, local communities, and regulators and these relationships are essential to our continued business success. We are deeply grateful for their passion, integrity and commitment to our vision. We also extend a sincere note of appreciation to our Board of Directors, who continue to provide a prudently balanced view of our growth. Finally, we offer our thanks to our shareholders for the trust they have placed in our company. We are eager to ensure we fulfill our goals to the benefit of our shareholders in 2016.

Sincerely,

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, 2015. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2015 and 2014. 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, 2016.

Caution concerning forward-looking statements and non-GAAP Measures

Forward-looking statements

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

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

Non-GAAP Financial Measures

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA"), "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales", are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share cash provided by adjusted funds from operations", Adjusted EBITDA, "net energy sales" and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales" and "net utility sales" can be found throughout this MD&A. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Use of Non-GAAP Financial Measures

Adjusted EBITDA

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

Adjusted net earnings

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

Adjusted funds from operations

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

Net energy sales

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

Net utility sales

Net utility sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodities are generally included as a pass through in rates to its utility customers. APUC uses net utility sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of net utility sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP. Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's 2014 Annual Information Form.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

APUC's current quarterly dividend to shareholders is U.S. $0.09625 per share or U.S. $0.3850 per share on an annual basis. Based on exchange rates as at March 10, 2016, the quarterly dividend is equivalent to CAD $0.12872 per share or CAD $0.51486 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

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

Generation Business Group

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

The Generation Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 700 MW, 30MW, and 335 MW respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

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

Distribution Business Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 489,000 connections, excluding the Park Water System. The Distribution Group provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

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

The Distribution Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, Missouri and New Hampshire; and together serve approximately 292,000 natural gas connections.

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together serve approximately 104,000 connections. On January 8, 2016, the Distribution Group completed its acquisition of the Park Water System which is comprised of two water and wastewater facilities in California and one facility in Montana. This acquisition adds another 74,000 connections to the Distribution Group's present water and wastewater footprint.

Transmission Business Group

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

Major Highlights

Corporate Highlights

Declaration of Canadian equivalent first quarter dividend of Cdn $0.1287 (U.S. $0.0963) per Common Share

On March 10, 2016, APUC announced that the Board of Directors of APUC declared the first quarter 2016 dividends of U.S. $0.0963 per common share. Based on the Bank of Canada noon exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2016 dividends is set at Cdn $0.1287 per common share.

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

	Q2 2015	Q3 2015	Q4 2015	Q1 2016	Total
U.S. dollar Dividend	$0.0963	$0.0963	$0.0963	$ 0.0963	$0.3850
Canadian dollar equivalent	$0.1201	$0.1289	$0.1267	$ 0.1287	$0.5044

Pending Acquisition of The Empire District Electric Company

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

Under the terms of the all-cash transaction, which has been unanimously approved by the Board of Directors of each company, Empire’s shareholders will receive U.S. $34.00 per common share (the “Purchase Price”), representing an aggregate purchase price of approximately $3.4 billion (U.S. $2.4 billion), including the assumption of approximately $1.3 billion (U.S. $0.9 billion) of debt as of September 30, 2015. The Purchase Price represents a 21% premium to the closing price on February 8, 2016 and a 50% premium to Empire’s unaffected share price on December 10, 2015.

Closing of the Acquisition is subject to customary closing conditions, including the approval of Empire’s common shareholders, and the receipt of certain state and federal regulatory and government approvals, including approval of the relevant commissions of the states of Arkansas, Kansas, Missouri and Oklahoma (collectively, the State Commissions), the Federal Communications Commission (the "FCC"), the Committee on Foreign Investment in the United States and the Federal Energy Regulatory Commission (the "FERC"), and the expiration or termination of the waiting period under the Hart-Scott-Rodino Act. The Transaction is expected to close in Q1 2017.

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.

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

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

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

On February 9, 2016, in connection with the acquisition of Empire, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.0 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering"). On March 9, 2016, the Underwriters exercised their option to purchase an additional $150 million of Debentures bringing the total amount of Debentures under the Debenture Offering to $1.15 billion.

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

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

U.S. $235 Million Term Credit Facility

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

$150 Million Bought Deal Offering Common Shares

On December 2, 2015 APUC issued on a bought deal basis (the "December Offering") 14,355,000 Common Shares at a price of $10.45 per share for gross proceeds of approximately $150 million.

Net proceeds of the December Offering are being used to partially fund APUC's capital growth program, to reduce short-term debt and for general corporate purposes.

Generation Group Highlights

Deerfield Wind Project Joint Venture

On October 19, 2015, the Generation Group announced it has agreed to jointly develop a 150 MW construction stage wind project (the "Deerfield Wind Project") in the United States with Renewable Energy Systems Americas Inc.

The Deerfield Wind Project is located in central Michigan and is being constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group. The project will utilize 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 power purchase agreement ("PPA") with a local electric distribution utility serving approximately 260,000 customers in Michigan.

The total project cost is expected to be approximately U.S. $303.0 million. The project is expected to achieve commercial operation at the end of 2016, with its first full year of operation being 2017.

Great Bay Solar Project

On December 1, 2015, the Generation Group announced the development of a new 75 MW contracted solar generation facility, located in Somerset County Maryland ("Great Bay Solar Project"). The U.S. $180.0 million facility will be constructed over the next twelve months, with commercial operations expected in late 2016 or early 2017. The facility is contracted under a 10 year PPA and expected to generate 152 GW-hrs annually. The facility will also generate SRECs which will be sold into the Maryland market.

Letter of Credit Facility

On October 30, 2015, the Generation Group entered into a new extendible one year letter of credit facility (the "Generation LC Facility") agreement. The new facility expands the group's available liquidity by providing for issuances of letters of credit based on two separate tranches of Cdn $50.0 million and U.S. $30.0 million. Upon closing, certain letters of credit issued on the existing Generation Credit Facility were transferred to the new facility.

Completion of Morse Wind Facility

On April 22, 2015 the Generation Group completed construction a 23 MW wind generating facility, located near Morse, Saskatchewan ("Morse Wind Project"). The facility is the Generation Group's eighth wind generating facility and consists of 10 2.3 MW direct drive wind turbine generators installed over 1,120 acres of land. The facility is expected to generate 104 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

Completion of Bakersfield I Solar Facility

On April 14, 2015 the Generation Group achieved commercial operation in accordance with the provisions within the PPA on the 20 MW solar generating facility located in Kern County, California (the "Bakersfield I Solar Facility"). The facility is the Generation Group's second solar generating facility and is comprised of approximately 85,000 solar panels located on 165 acres of land. The project is expected to generate 53.3 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

Consistent with the commitment to expand its solar generation portfolio, the Generation Group is currently pursuing the construction of the 10 MW Bakersfield II Solar Project immediately adjacent to the Bakersfield I Solar Generation Project, which is estimated to be operational in the first half of 2016.

Distribution Group Highlights

Acquisition of the Park Water System

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

Total consideration for the utility purchase was U.S. $341.8 million, which includes the assumption of approximately U.S. $91.8 million of existing long-term utility debt. This acquisition maintains APUC's strategic business mix and further enhances its investment grade consolidated capital structure.

The water utility located in western Montana is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water (see *Enterprise Risk Management*, *Regulatory Risk*).

Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure an appropriate return on the rate base at its various utility systems. During 2015, the Distribution Group successfully completed several rate cases representing a cumulative annual revenue increase of approximately U.S. $18.1 million. Subsequent to the year end, the Distribution Group concluded the New England Natural Gas and Peach State Natural Gas System rate cases which resulted in U.S. $11.0 million in increased rates. The full annualized impact of these rate cases will be realized in 2016.

U.S. Debt Private Placement

On April 30, 2015, the Distribution Group entered into a Note Purchase Agreement for the issuance of U.S. $160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing was used to partially finance the acquisition of the Park Water System and for general corporate purposes. The notes were issued in two tranches: U.S. $90.0 million was issued immediately on closing and U.S. $70.0 million were issued on July 15, 2015. The notes have been assigned a rating of BBB High by DBRS.

The financing is the fourth series of notes issued pursuant to the company's master indenture.

Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group 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 was approximately U.S. $3.0 million, subject to certain closing adjustments.

Transmission Group Highlights

Northeast Supply Pipeline

In December 2015, the Transmission Group reached an agreement for acquiring an additional equity investment right in the Supply Link segment to the Northeast Expansion Pipeline, referred to as Northeast Supply Pipeline ("NSP Project") a joint venture with subsidiaries of Kinder Morgan. The project is a 30 inch greenfield pipeline from northeastern Pennsylvania to Wright, New York traversing 132 miles and having a design capacity of up to 1,200,000 dth/day. The Transmission Group has secured a 4% initial participation right, along with an option to increase its participation to 10%.

The Northeast Expansion Pipeline ("NEP Project") and the NSP Project developer, Tennessee Gas Pipeline, filed a combined FERC application for a Certificate of Public Convenience and Necessity along with a complete Environmental Review in November 2015. A November 2016 FERC order has been requested and a November 2018 project in service date is planned.

2015 Fourth Quarter Results From Operations

Key Selected Fourth Quarter Financial Information

(all dollar amounts in $ millions except per share information)	Three months ended December 31 2015		Three months ended December 31 2014	
Revenue	**$**	**260.3**	$	259.3
Adjusted EBITDA [1]		**109.6**		84.3
Cash provided by operating activities		**94.3**		96.5
Adjusted funds from operations[1]		**77.2**		65.9
Net earnings attributable to Shareholders from continuing operations		**38.1**		33.1
Net earnings attributable to Shareholders		**38.0**		31.6
Adjusted net earnings[1]		**39.7**		35.2
Dividends declared to Common Shareholders		**34.0**		25.4
Weighted Average number of common shares outstanding		**258,048,584**		230,664,583
Per share				
Basic net earnings/(loss) from continuing operations	**$**	**0.14**	$	0.13
Basic net earnings/(loss)	**$**	**0.14**	$	0.13
Adjusted net earnings[1, 2,]	**$**	**0.15**	$	0.14
Diluted net earnings/(loss)	**$**	**0.14**	$	0.12
Cash provided by operating activities [1,2]	**$**	**0.38**	$	0.42
Adjusted funds from operations[1,2]	**$**	**0.30**	$	0.27
Dividends declared to Common Shareholders	**$**	**0.13**	$	0.10

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2015, APUC experienced an average U.S. exchange rate of approximately $1.335 as compared to $1.136 in the same period in 2014. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended December 31, 2015, APUC reported total revenue of $260.3 million as compared to $259.3 million during the same period in 2014, an increase of $1.0 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2015 as compared to the corresponding period in 2014 are set out as follows:

(all dollar amounts in $ millions)		Three months ended December 31, 2015
Comparative Prior Period Revenue	$	**259.3**
Existing Facilities: Generation		
Hydro Canada: The hydro facilities realized lower production rates at the Quebec and Maritime region.		(2.9)
Wind Canada: The St Leon Wind Facility experienced decreased wind resources.		(0.8)
Wind US: Increased wind resources at the Minonk and Shady Oaks Wind Facilities coupled with an increase in market pricing for the sale of REC's. These gains were partially offset by lower wind resources at the Senate and Sandy Ridge Wind Facilities.		4.6
Solar Canada: The Cornwall Solar Facility Experienced increased solar resource.		0.4
Thermal: The thermal facilities experienced a lower cost of gas (which is a direct pass-through to customers).		(1.6)
Other		(0.2)
		(0.5)
New Facilities: Generation		
Wind Canada: Increase due to the St Damase and Morse Wind Facilities achieving commercial operations in Q4 2014 and Q2 2015.		4.2
Solar US: Bakersfield I Solar Facility which achieved commercial operation within the provisions of the PPA in Q2 2015.		0.4
		4.6
Foreign Exchange		
Increased Generation Group operating profit as a result of a stronger U.S. dollar.		**7.3**
Existing Facilities: Distribution		
Electric Distribution Systems: Decrease in revenue due to decrease in GW-hrs used by commercial customers, partially offset by an increase in revenue at the Calpeco Electric System.		(7.0)
Natural Gas Distribution Systems: Decrease in Natural Gas Distribution Systems revenues due to lower commodity cost (which are a direct pass-through to customers) and decreased customer demand.		(27.5)
Water Distribution & Wastewater Treatment Systems: Revenue excluding rate case impact was in line with prior year.		0.2
Other Income: Decreased revenues from contracted services.		(2.9)
		(37.2)
New Facilities: Distribution		
Natural Gas Distribution Systems: Increase due to New Hampshire Gas which was acquired in Q1 2015.		0.7
Water Distribution & Wastewater Treatment Systems: Decreased demand at the Whitehall Water System.		(0.2)
		0.5
Rate Cases		
Natural Gas Distribution Systems: Successful implementation of new rates at the EnergyNorth and the Missouri Natural Gas System.		3.3
Water Distribution & Wastewater Treatment Systems: Successful implementation of new rates at the LPSCo Water System.		0.2
		3.5
Foreign Exchange		
Increased Distribution Group operating profit as a result of a stronger U.S. dollar.		**22.8**
Current Period Revenue	$	**260.3**

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

Adjusted EBITDA in the three months ended December 31, 2015 totalled $109.6 million as compared to $84.3 million during the same period in 2014, an increase of $25.3 million or 30.0%. The increase in Adjusted EBITDA was primarily due to the St. Damase Wind, Morse Wind, and Bakersfield I Solar Facilities achieving commercial operations, the impact of rate case settlements, increased wind resources, and a stronger U.S. dollar. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Performance Measures*).

For the three months ended December 31, 2015, net earnings attributable to Shareholders from continued operations totalled $38.1 million as compared to $33.1 million during the same period in 2014, an increase of $5.0 million or 15.1%. The increase was due to $22.9 million in increased earnings from operating facilities, $1.2 million in increased interest and dividend income, $2.1 million in decreased gains, $1.1 million in decreased acquisition costs, $2.0 million in increased gains from derivative instruments, and $3.6 million in increased loss attributable to non-controlling interests, as compared to the same period in 2014. These items were partially offset by $12.9 million in increased depreciation and amortization expenses, $2.7 million in increased administration charges, $3.3 million in increased interest expense, $1.0 million increased write-downs on long-lived assets and loss on disposal, and $8.1 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses).*

For the three months ended December 31, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled $38.0 million as compared to net earnings attributable to Shareholders of $31.6 million during the same period in 2014, an increase of $6.4 million or 20.3%. Net earnings per share totalled $0.14 for the three months ended December 31, 2015, as compared to net earnings per share of $0.13 during the same period in 2014.

During the three months ended December 31, 2015, cash provided by operating activities totalled $94.3 million or $0.38 per share as compared to cash provided by operating activities of $96.5 million, or $0.42 per share during the same period in 2014. During the three months ended December 31, 2015, adjusted funds from operations totalled $77.2 million or $0.30 per share as compared to adjusted funds from operations of $65.9 million, or $0.27 per share during the same period in 2014. The change in adjusted funds from operations in the three months ended December 31, 2015, is primarily due to increased earnings from operations, as compared to the same period in 2014.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2015 Annual Results From Operations

As outlined, APUC has continued to advance growth initiatives throughout 2015 that had a positive contribution to the annual results.

Key Selected Annual Financial Information

(all dollar amounts in $ millions except per share information)	Twelve months ended December 31 2015	2014	2013
Revenue	**$ 1,027.9**	$ 941.6	$ 675.3
Adjusted EBITDA [1]	**375.4**	290.5	228.1
Cash provided by operating activities	**261.9**	192.7	98.9
Adjusted funds from operations[1]	**287.4**	206.5	154.9
Net earnings attributable to Shareholders from continuing operations	**118.5**	77.8	62.3
Net earnings attributable to Shareholders	**117.5**	75.7	20.3
Adjusted net earnings [1]	**121.5**	88.2	59.5
Dividends declared to Common Shareholders	**124.6**	82.9	68.3
Weighted Average number of common shares outstanding	**253,172,088**	213,953,870	204,350,689
Per share			
Basic net earnings from continuing operations	**$ 0.43**	$ 0.32	$ 0.28
Basic net earnings	**$ 0.42**	$ 0.31	$ 0.07
Adjusted net earnings [1, 2]	**$ 0.46**	$ 0.37	$ 0.26
Diluted net earnings	**$ 0.42**	$ 0.31	$ 0.07
Cash provided by operating activities [1, 2]	**$ 1.09**	$ 0.90	$ 0.48
Adjusted funds from operations[1, 2]	**$ 1.15**	$ 0.92	$ 0.73
Dividends declared to Common Shareholders	**$ 0.49**	$ 0.37	$ 0.33
Total assets	**4,991.7**	4,102.8	3,469.3
Long term debt [3]	**1,486.8**	1,271.7	1,248.3

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

3 Includes long-term debt and current portion of long-term debt

For the year ended December 31, 2015, APUC experienced an average U.S. exchange rate of approximately $1.2786 as compared to $1.1049 in the same period in 2014. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the year ended December 31, 2015, APUC reported total revenue of $1,027.9 million as compared to $941.6 million during the same period in 2014, an increase of $86.3 million or 9.2%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2015 as compared to the corresponding period in 2014 are set out as follows:

(all dollar amounts in $ millions)		Twelve months ended December 31, 2015
Comparative Prior Year Revenue	**$**	**941.6**
Existing Facilities: Generation		
Hydro Canada: The hydro facilities realized lower production rates at the Quebec and Maritime Region.		(11.1)
Wind Canada: The St Leon Wind Facility experienced decreased wind resources.		(1.7)
Wind US: Increased wind resources at the Minonk and Shady Oaks Wind Facilities coupled with an increase in market pricing for the sale of REC's.		9.2
Solar Canada: The Cornwall Solar Facility experienced increased solar resource.		1.3
Thermal: The thermal facilities experienced a lower cost of gas (which is a direct pass-through to customers).		(8.4)
Other		(0.3)
		(11.0)
New Facilities: Generation		
Wind Canada: Increase due to the St Damase and Morse Wind Facilities achieving commercial operations in Q4 2014 and Q2 2015, respectively.		13.4
Solar US: Bakersfield I Solar Facility which achieved commercial operation within the provisions of the PPA in Q2 2015.		2.8
		16.2
Foreign Exchange		
Increased Generation Group operating profit as a result of a stronger U.S. dollar.		**20.8**
Existing Facilities: Distribution		
Electric Distribution Systems: Decrease in revenue due to decrease in GW-hrs used by commercial customers, partially offset by an increase in revenue at the Calpeco Electric System.		(7.1)
Natural Gas Distribution Systems: Decrease in Natural Gas Distribution Systems revenues due to lower commodity cost) which are a direct pass-through to customers) and decreased customer demand.		(58.7)
Other Income: Increase in revenue from contracted services.		8.2
Other		(1.5)
		(59.1)
New Facilities: Distribution		
Natural Gas Distribution Systems: Increase due to New Hampshire Gas which was acquired in Q1 2015.		3.3
Water Distribution & Wastewater Treatment Systems: Increase due to White Hall Water & Waste System which was acquired in Q2 2014.		1.3
		4.6
Rate Cases		
Electric Distribution Systems: In 2014 the Granite State Electric System retroactively recognized rates pertaining to its 2014 rate case settlement. A similar adjustment was not made in 2015.		(2.4)
Natural Gas Distribution Systems: Successful implementation of new rates at the EnergyNorth, Illinois, Georgia and the Missouri Natural Gas Systems.		19.9
Water Distribution & Wastewater Treatment Systems: Successful implementation of new rates at the LPSCo Water System.		1.3
		18.8
Foreign Exchange		
Increased Distribution Group operating profit as a result of a stronger U.S. dollar.		**96.0**
Current Year Revenue	**$**	**1,027.9**

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

Adjusted EBITDA in the year ended December 31, 2015 totalled $375.4 million as compared to $290.5 million during the same period in 2014, an increase of $84.9 million or 29.2%.

For the year ended December 31, 2015, net earnings from continuing operations attributable to Shareholders totalled $118.5 million as compared to $77.8 million during the same period in 2014, an increase of $40.7 million. The increase was due to $85.7 million in increased earnings from operating facilities, $1.5 million in increased foreign exchange gains, $5.1 million due to increased other gains, $1.3 million increased dividend, equity and other income, $0.7 million decreased acquisition related costs, $5.1 million decrease in write-down of long lived assets, $3.6 million increase in gains on derivative financial instruments and $9.8 million increased loss attributable to non-controlling interest as compared to the same period in 2014. These items were partially offset by $35.8 million in increased depreciation and amortization expenses, $6.0 million in increased administration charges, $3.6 million in increased interest expense and $26.9 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses),* as compared to the same period in 2014.

For the year ended December 31, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled $117.5 million as compared to $75.7 million during the same period in 2014, an increase of $41.8 million. Net earnings per share totalled $0.42 for the year ended December 31, 2015, as compared to $0.31 during the same period in 2014.

During the year ended December 31, 2015, cash provided by operating activities totalled $261.9 million or $1.09 per share as compared to cash provided by operating activities of $192.7 million, or $0.90 per share during the same period in 2014. During the year ended December 31, 2015, adjusted funds from operations, a non-GAAP measure, totalled $287.4 million or $1.15 per share as compared to adjusted funds from operations of $206.5 million, or $0.92 per share during the same period in 2014, an increase of $80.9 million.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2015 Adjusted EBITDA Summary

Adjusted EBITDA in the year ended December 31, 2015 totalled $375.4 million as compared to $290.5 million during the same period in 2014, an increase of $84.9 million or 29.2%. Adjusted EBITDA (see non-GAAP measures) in the three months ended December 31, 2015 totalled $109.6 million as compared to $84.3 million during the same period in 2014, an increase of $25.3 million or 30.0%. The breakdown of Adjusted EBITDA (see *Non-GAAP Performance Measures*) by the company's main operating segments and a summary of changes is shown below.

Adjusted EBITDA by segment	**Three months ended December 31**				**Twelve months ended December 31, 2015**			
(all dollar amounts in $ millions)		**2015**		**2014**		**2015**		**2014**
Generation Business Group Operating Profit	**$**	**62.0**	$	47.9	**$**	**188.9**	$	156.0
Distribution Business Group Operating Profit		**59.3**		46.6		**224.4**		166.4
Administration Expenses		**(13.2)**		(10.5)		**(40.7)**		(34.7)
Other Income & Expenses		**1.5**		0.3		**2.8**		2.8
Total Algonquin Power & Utilities Adjusted EBITDA	**$**	**109.6**	$	84.3	**$**	**375.4**	$	290.5
Change in Adjusted EBITDA ($)	$	25.3			$	84.9		
Change in Adjusted EBITDA (%)		30.0%				29.2%		

Change in Adjusted EBITDA Breakdown	**Twelve months ended December 31, 2015**							
(all dollar amounts in $ millions)		**Generation**		**Distribution**		**Corporate**		**Total**
Prior period Balances	**$**	**156.0**	**$**	**166.4**	**$**	**(31.9)**	**$**	**290.5**
Existing Facilities		(1.9)		7.0		—		5.1
New Facilities		17.2		0.7		—		17.9
Rate Cases		—		18.8		—		18.8
Foreign Exchange Impact		17.6		31.5		—		49.1
Administration Expenses		—		—		(6.0)		(6.0)
Total change during the period	**$**	**32.9**	**$**	**58.0**	**$**	**(6.0)**	**$**	**84.9**
Current Period Balances	**$**	**188.9**	**$**	**224.4**	**$**	**(37.9)**	**$**	**375.4**

Change in Adjusted EBITDA Breakdown	**Three months ended December 31**							
(all dollar amounts in $ millions)		**Generation**		**Distribution**		**Corporate**		**Total**
Prior period Balances	**$**	**47.9**	**$**	**46.6**	**$**	**(10.2)**		**84.3**
Existing Facilities		1.8		0.2		1.2		3.2
New Facilities		4.9		—		—		4.9
Rate Cases		—		3.5		—		3.5
Foreign Exchange Impact		7.4		9.0		—		16.4
Administration Expenses		—		—		(2.7)		(2.7)
Total change during the period	**$**	**14.1**	**$**	**12.7**	**$**	**(1.5)**	**$**	**25.3**
Current Period Balances	**$**	**62.0**	**$**	**59.3**	**$**	**(11.7)**	**$**	**109.6**

GENERATION BUSINESS GROUP

The Company's management's reporting structure is aligned under three business units: Generation, Transmission and Distribution Business Groups. During the fourth quarter, Management determined that each business unit represents a reporting segment. The comparative information for 2014 has been reclassified to conform with the composition of the reporting segments presented in the current year. At present the Transmission Business group is not material and is therefore grouped with Corporate.

2015 Electricity Generation Performance

	Long Term Average Resource	Three months ended December 31		Long Term Average Resource	Twelve months ended December 31, 2015	
		2015	2014		2015	2014
Performance (GW-hrs sold)						
Hydro Facilities:						
Maritime Region	45.8	40.4	47.2	177.8	141.8	140.3
Quebec Region[1]	72.6	72.8	72.3	273.9	260.9	259.4
Ontario Region	31.9	34.3	38.7	133.7	140.7	144.4
Western Region	12.6	13.6	13.4	65.0	56.2	74.1
	162.9	161.1	171.6	650.4	599.6	618.2
Wind Facilities:						
St. Damase[2]	22.7	20.7	4.7	76.9	73.4	4.7
St. Leon	121.4	106.1	119.9	430.2	408.7	441.4
Red Lily[3]	24.1	20.7	23.8	88.5	78.8	87.7
Morse	30.5	24.0	—	73.9	61.3	—
Sandy Ridge	43.6	43.7	46.7	158.3	150.0	149.0
Minonk	189.7	214.6	195.4	673.7	639.3	648.5
Senate	140.0	134.7	139.0	520.4	467.6	537.6
Shady Oaks	100.5	114.5	92.2	355.6	342.6	339.9
	672.5	679.0	621.7	2,377.5	2,221.7	2,208.8
Solar Facilities:						
Cornwall	2.1	2.3	1.8	14.6	15.2	12.8
Bakersfield	8.9	6.4	—	43.7	36.1	—
	11.0	8.7	1.8	58.3	51.3	12.8
Thermal Facilities:						
Windsor Locks	N/A[4]	25.5	26.3	N/A[4]	131.9	112.4
Sanger	N/A[4]	32.4	35.1	N/A[4]	129.8	134.2
		57.9	61.4		261.7	246.6
Total Performance	**846.4**	**906.7**	**856.5**	**3,086.2**	**3,134.3**	**3,086.4**

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

2 The St Damase Wind Facility achieved commercial operation on December 2, 2014.

3 APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility under contract and has an option to acquire a 75% equity interest in the facility in 2016.

4 Natural gas fired co-generation facility.

2015 Fourth Quarter Generation Performance

For the three months ended December 31, 2015, the Generation Group generated 906.7 GW-hrs of electricity as compared to 856.5 GW-hrs during 2014

For the quarter, the hydro facilities generated 161.1 GW-hrs of electricity, as compared to 171.6 GW-hrs produced in the same period in 2014, a decrease of 6.1%. Electricity generated represented 98.9% of long-term average resources ("LTAR") as compared to 105.3% during the same period in 2014. The decreased generation is largely attributable to weaker hydrology in the Maritimes and Ontario regions.

For the three months ended December 31, 2015, the wind facilities produced 679.0 GW-hrs of electricity, as compared to 621.7 GW-hrs produced in the same period in 2014, an increase of 9.2%. The higher generation was a result of increased wind resources at Shady Oaks and Minonk Wind Facilities, in addition to the St. Damase and Morse Wind Facilities achieving commercial operation in December 2014 and April 2015, respectively. During the three months ended December 31, 2015, the wind facilities (excluding the St. Damase and Morse Wind Facilities) generated electricity equal to 102.4% of LTAR, as compared to 99.7% during the same period in 2014, due to variability in the wind resource.

For the three months ended December 31, 2015, the solar facilities generated 8.7 GW-hrs of electricity, as compared to 1.8 GW-hrs of electricity in the same period in 2014, an increase of 383.3%. The increase in production is attributable to the new Bakersfield I Solar Facility which achieved commercial operation in accordance with the provisions of the PPA on April 14, 2015. Cornwall's production was 9.5% above its LTAR, as compared to 14.3% below its LTAR in the same period last year. Bakersfield I Solar Facility achieved 71.1% of its LTAR primarily due to an equipment malfunction which damaged the inverter houses, impacting 30% of the facility. Repairs of the damaged inverter houses were completed in the fourth quarter of 2015.

For the three months ended December 31, 2015, the thermal facilities generated 57.9 GW-hrs of electricity, as compared to 61.4 GW-hrs of electricity during the same period in 2014. During the same period, the Windsor Locks Thermal Facility generated 143.0 billion lbs of steam, as compared to 157.3 billion lbs of steam during the same period in 2014.

2015 Twelve Month Generation Performance

For the twelve months ended December 31, 2015, the Renewable Energy Division generated 3,134.3 GW-hrs of electricity as compared to 3,086.4 GW-hrs during 2014.

For the twelve months ended December 31, 2015, the hydro facilities generated 599.6 GW-hrs of electricity, as compared to 618.2 GW-hrs produced in the same period in 2014, a decrease of 3.0%. Electricity generated represented 92.2% of long-term projected average resources, as compared to 95.0% during the same period in 2014. During the twelve months ended December 31, 2015, the Ontario Hydro region achieved production above its LTAR, while the Quebec, Western and Maritime regions were below their respective LTAR. The Quebec region was below its LTAR predominantly due to the Donnaconna Hydro Facility being offline during the year. Excluding the Donnacona Hydro Facility, the Quebec region would have achieved 103% of the long term average hydrological resource.

For the twelve months ended December 31, 2015, the wind facilities produced 2,221.7 GW-hrs of electricity, as compared to 2,208.8 GW-hrs produced in the same period in 2014, an increase of 0.6%. During the twelve months ended December 31, 2015, the wind facilities generated electricity equal to 93.4% of LTAR, as compared to 98.9% during the same period in 2014. The incremental electricity generated from St. Damase and Morse Wind Facilities in 2015 was offset by weaker wind resources at the St. Leon and Senate Wind Facilities.

For the twelve months ended December 31, 2015, the solar facilities generated 51.3 GW-hrs of electricity as compared to 12.8 GW-hrs of electricity produced in the same period in 2014, an increase of 300.8%. The Cornwall Solar Facility's production was equal to 4.1% above its LTAR as compared to 10.3% above its LTAR in the same period last year from its commercial operation date in 2014. The Bakersfield I Solar Facility's production was 17.4% below its LTAR, due to the inverter house malfunction during the year. The increase in production is attributable to the first full year of production at the Cornwall Solar Facility and the new Bakersfield I Solar Facility which achieved COD on April 14, 2015 in accordance with the provisions of the PPA.

For the twelve months ended December 31, 2015, the thermal facilities generated 261.7 GW-hrs of electricity, as compared to 246.6 GW-hrs of electricity during the same period in 2014. During the same period, the Windsor Locks Thermal Facility generated 567.7 billion lbs of steam, as compared to 609.1 billion lbs of steam during the same period in 2014.

2015 Generation Group Operating Results

(all dollar amounts in $ millions)	Three months ended December 31 2015	Three months ended December 31 2014	Twelve months ended December 31, 2015 2015	Twelve months ended December 31, 2015 2014
Revenue[1]				
Hydro	**14.6**	16.8	**55.7**	65.1
Wind	**38.7**	27.0	**118.0**	88.9
Solar	**1.6**	0.7	**10.3**	5.5
Thermal	**8.1**	9.0	**38.5**	43.0
Total Revenue	**$ 63.0**	**$ 53.5**	**$ 222.5**	**$ 202.5**
Less:				
Cost of Sales - Energy[2]	**(1.7)**	(1.5)	**(10.3)**	(16.7)
Cost of Sales - Thermal	**(3.6)**	(5.0)	**(17.7)**	(22.6)
Realized gain/(loss) on hedges[3]	**—**	(0.2)	**0.6**	3.6
Net Energy Sales	**$ 57.7**	$ 46.8	**$ 195.1**	$ 166.8
Renewable Energy Credits ("REC")[4]	**6.1**	4.0	**18.5**	13.1
Other Revenue	**0.9**	1.1	**3.8**	3.2
Total Net Revenue	**$ 64.7**	$ 51.9	**$ 217.4**	$ 183.1
Expenses & Other Income				
Operating expenses	**(15.0)**	(13.0)	**(63.6)**	(55.5)
Interest and Other income	**(0.3)**	0.1	**1.2**	1.2
HLBV income	**12.6**	8.9	**33.9**	27.2
Divisional operating profit	**$ 62.0**	$ 47.9	**$ 188.9**	$ 156.0

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

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

3 See financial statements note 24(b)(iv).

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

2015 Fourth Quarter Operating Results

For the three months ended December 31, 2015, the Generation Group facilities generated $62.0 million of operating profit as compared to $47.9 million during the same period in 2014, which represents an increase of $14.1 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, 2015
Prior Period Operating Profit	**$**	**47.9**
Existing Facilities		
Hydro Canada: The hydro facilities realized lower production rates at the Quebec and Maritime regions.		(2.6)
Wind Canada: The St Leon Wind Facility experienced decreased wind resources.		(0.6)
Wind US: The U.S. wind facilities experienced increased wind resources at the Minonk and Shady Oaks Wind Facilities, and increased market pricing for the sale of Renewable Energy Credits ("RECs"). This was offset by lower wind resources at the Senate and Sandy Ridge Wind Facilities.		5.4
Solar Canada: The Cornwall Solar Facility experienced increased solar resource.		0.5
Thermal: The thermal facilities experienced lower production at both the Windsor Locks and Sanger Thermal Facilities.		(0.4)
Other		(0.5)
		1.8
New Facilities		
Wind Canada: The increase was due to the St. Damase and Morse Wind Facilities achieving commercial operations on Dec 2014 and April 2015, respectively.		3.6
Solar US: Bakersfield I Solar Facility which achieved commercial operation in accordance with the provisions of the PPA in April 2015.		1.3
		4.9
Foreign Exchange		
Increased operating profit as a result of a stronger U.S. dollar.		**7.4**
Current Period Operating Profit	**$**	**62.0**

2015 Twelve Month Operating Results

For the twelve months ended December 31, 2015, the Generation Group facilities generated $188.9 million of operating profit as compared to $156.0 million during the same period in 2014, which represents an increase of $32.9 million or 21.1%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve months ended December 31, 2015
Prior Period Operating Profit	**$**	**156.0**
Existing Facilities		
Hydro Canada: The decreased operating profit at the hydro facilities were primarily a result of the Donnaconna Hydro Facility being offline for the full year in 2015, lower hydrology, and lower demand in the Maritime region. These items were partially offset by increased hydrology at sites other than Donnaconna in the Quebec region.		(6.1)
Wind Canada: The St Leon Wind Facility experienced decreased wind resources.		(1.7)
Wind US: The U.S. wind facilities realized higher pricing on the unhedged portion of energy production, and higher pricing for RECs in the PJM market, partially offset by lower production and resulting lower HLBV income.		7.2
Solar Canada: The increase is due to the Cornwall Solar Facility completing its first full year of production as the site achieved commercial operation on March 27, 2014.		1.0
Thermal: The thermal facilities experienced lower production at both the Windsor Locks and Sanger Thermal Facilities.		(2.2)
Other		(0.1)
		(1.9)
New Facilities		
Wind Canada: The increase was due to the St. Damase and the Morse Wind Facilities achieving commercial operations in December 2014 and April 2015, respectively.		11.6
Solar US: The increase was due to operating and HLBV income associated with the Bakersfield I Solar Facility which achieved commercial operation in accordance with the provisions of the PPA in April 2015.		5.6
		17.2
Foreign Exchange		
Increased operating profit as a result of a stronger U.S. dollar.		**17.6**
Current Period Operating Profit	**$**	**188.9**

GENERATION BUSINESS GROUP

Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire operating projects that would be complementary and accretive to the Generation Group's existing portfolio. The Development Division is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. The Generation Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This 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 Generation Group's Development Division will begin construction or execute an acquisition agreement.

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

Project Name	Location	Size (MW)		Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Total Project in Construction							
Odell Wind Project[1]	Minnesota	200	$	446.8	2016	20	814.7
Val Eo Wind Project[2]	Quebec	24	$	70.0	2016/17	20	66.0
Bakersfield II Solar Project[3]	California	10	$	37.4	2016	20	24.2
Deerfield Wind Project[4]	Michigan	150	$	419.4	2016	20	555.2
Great Bay Solar Project[5]	Maryland	75	$	249.1	2016/17	10	152.0
		459	**$**	**1,222.7**			**1,612.1**
Projects in Development							
Amherst Island Wind Project	Ontario	75	$	272.5	2017	20	235.0
Chaplin Wind Project	Saskatchewan	177	$	340.0	2017/18	25	720.0
Total Projects in Development		**252**	**$**	**612.5**			**955.0**
Total in Construction and Development		**711**	**$**	**1,835.2**			**2,567.1**

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

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

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

4 The total cost of the project is expected to be approximately $303.0 million in U.S. dollars

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

Projects Completed

Bakersfield I Solar Facility

The Bakersfield I Solar Facility is a 20 MWac solar powered electric generating facility located in Kern County, California.

The facility is comprised of approximately 85,000 solar panels located on 165 acres of land and is expected to generate 53.3 GW-hrs of energy per year with all energy from the facility being sold to a large investment grade electric utility pursuant to a 20 year PPA.

Construction of the facility commenced in the second quarter of 2014 and the facility was placed in service on December 30, 2014. On April 14, 2015 the facility achieved commercial operation in accordance with the provisions within the PPA. The total cost to complete the facility was U.S. $58.4 million.

The Generation Group has entered into a partnership agreement with a third party where the third party contributed U.S. $22.4 million to the project and in return will receive the majority of the tax attributes.

Morse Wind Facility

The Morse Wind Facility is a 23 MW wind powered electric generating facility located near Morse, Saskatchewan, approximately 180 km west of Regina.

The facility is comprised of approximately 10 turbines spread over three contiguous facilities and is expected to generate 104 GW-hrs of energy per year, with all energy from the project being sold to SaskPower pursuant to a 20 year PPA under the Green Options Partner Program.

Construction of the facility commenced in the third quarter of 2014 and the facility reached commercial operation on April 22, 2015 with all 10 turbines completed and selling power under the provisions of the PPA. The total cost to complete the facility was $81.7 million.

Projects in Construction

Odell Wind Project

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

The project will be comprised of 100 Vestas V110-2.0 wind turbines and is expected to generate 814.7 GW-hrs of energy per year with all energy, capacity and renewable energy credits from the project sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the Midwest, pursuant to a 20 year PPA.

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

The total costs to complete the project are estimated at approximately U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits, accordingly the project company has entered into a partnership agreement with third parties (tax equity) to contribute approximately U.S. $180 million to the project in return for the majority of the tax attributes. Construction financing, including a portion that bridges to tax equity's investment, was arranged by the project company during 2015.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of commercial operations, which is expected in the third quarter of 2016.

Val-Éo Wind Project

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

The project will be developed in two phases: Phase I of the project is expected to be completed in 2017 and will comprise of eight 3.0 MW wind turbines and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project sold to Hydro Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

All land agreements, construction permits, and authorizations have been obtained for Phase I. After the permitting process was delayed at the provincial level, construction planned in 2015 has been re-evaluated due to the severe weather conditions in the region. The new schedule calls for construction to begin in the second quarter of 2016 as such the project is expected to now reach commercial operations in late 2016 or early 2017. Total costs to complete the project are estimated at approximately $70.0 million.

The 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.

Bakersfield II Solar Project

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

The project is located on 64 acres of land and is expected to generate 24.2 GW-hrs of energy per year with all energy from the project sold to the same large investment grade electric utility as Bakersfield I Solar Facility, pursuant to a 20 year PPA.

Construction of the project commenced in the second quarter of 2015. Project permits with the county and an EPC contractor are at an advanced stage. The project has a commercial operations date targeted for the second quarter of 2016.

The total costs to complete the project are estimated at approximately U.S. $27.0 million and are expected to be funded with a combination of senior debt, common equity, and contributions from tax equity investors. Consistent with financing structures utilized for U.S. based renewable energy projects including Bakersfield I Solar, it is anticipated that Bakersfield II Solar will source financing in the amount of approximately 40% of the capital costs from certain tax equity investors.

Deerfield Wind Project

The Deerfield Wind Project is a 150.0 MW wind powered electric generating development project located in central Michigan and is being constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group.

The project will comprise 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.

Construction of the project commenced in the fourth quarter of 2015. Over 90% of the private land access roads have been constructed and public road improvements are underway. The main power transformer procurement has been finalized, and engineering for the project is nearing completion. The project has a commercial operations date targeted for the fourth quarter of 2016.

The total costs to complete the project are estimated at approximately U.S. $303.0 million. It is anticipated that the Deerfield Wind Project will qualify for U.S. federal production tax credits, accordingly, approximately 50% of the permanent project financing is expected to be funded by tax equity investors in return for the majority of the tax attributes.

The Generation Group's interest in the project is via a 50% joint venture with the original developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments any time prior to the date that is 90 days following commencement of operations.

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 project is expected to generate 152.0 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 second quarter of 2016. The project has received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission. The EPC contract has been executed, and equipment procurement is in progress, with deliveries to the site beginning in the third quarter of 2016. The project has a commercial operations date targeted for late 2016 or early 2017.

The total costs to complete the project are estimated at approximately U.S. $180.0 million. The Generation Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately U.S. $62.0 million 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

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. In February 2011, the 75 MW project was awarded a Feed-In-Tariff (“FIT”) contract by the OPA as part of the second round of the OPA’s FIT program.

The total costs to complete the project is estimated at approximately $272.5 million. The project is currently contemplated to use Class III wind turbine generator technology. The available wind resource is forecast to produce approximately 235.0 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Final negotiations on the turbine supply agreement are ongoing; and engineering, procurement and construction contractor selection is underway. The project has a commercial operations date targeted for 2017.

The Renewable Energy Approval ("REA") was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment. An appeal of the REA has been made to the Environmental Review Tribunal (“ERT”). The appeal process is generally limited to a period of 6 months, although the ERT may grant extensions in appropriate cases. It is anticipated that the hearing will extend beyond 6 months and is likely to conclude in April 2016. Other permitting processes and the engineering and procurement of long-lead time equipment are progressing according to schedule, including the supply of turbines for the project. The project has a planned construction time frame of approximately 12 months.

Chaplin Wind Project

The Chaplin Wind Project is a 177.0 MW wind powered electric generating development project located in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2017 and is expected to generate approximately 35 MW of the total project, with all energy from Phase I of the project sold to SaskPower pursuant to a 25 year PPA; Phase II of the project, which comprises the remaining approximately 142 MW, will be the infill construction phase and will only proceed following evaluation of the wind resource at the site, and completion of satisfactory permitting.

The total costs to complete the project are estimated at approximately $340.0 million but are subject to change depending on turbine selection. Depending on the size of the turbines used, the number of pads will vary from 58 to 70, and energy may vary from 659-766 GW-hrs. Final selection will be based on multiple factors including an assessment of the internal rate of return. The PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of its favorable location by interconnecting with a nearby 138kV line and will be compliant with SaskPower's latest interconnection requirements. The project has a commercial operations date targeted for late 2017 or early 2018.

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

DISTRIBUTION BUSINESS GROUP

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 489,000 connections, excluding the Park Water System, in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	December 31, 2015		December 31, 2014	
(all dollar amounts in U.S. $ millions)	Assets	Connections	Assets	Connections
Electricity	**$ 343.2**	**93,000**	$ 325.0	93,000
Natural Gas	**783.0**	**292,000**	726.0	292,000
Water and Wastewater	**254.7**	**104,000**	261.2	103,000
Total	**$ 1,380.9**	**489,000**	$ 1,312.2	488,000
Accumulated Deferred Income Taxes	**$ 110.3**		$ 79.6	

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

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

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 292,000 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 104,000 connections located in the states of Arkansas, Arizona, Texas, Illinois, and Missouri. On January 8, 2016, the Distribution Group completed its acquisition of the Park Water System which is comprised of two water and wastewater facilities in California and one facility in Montana. This acquisition adds another 74,000 connections to the Distribution Group's present water and wastewater footprint.

2015 Fourth Quarter Usage Results

Electric Distribution Systems	Three months ended December 31	
	2015	2014
Average Active Electric Connections For The Period		
Residential	**80,000**	80,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**92,000**	92,000
Customer Usage (GW-hrs)		
Residential	**135.8**	134.9
Commercial and Industrial	**220.3**	230.5
Total Customer Usage (GW-hrs)	**356.1**	365.4

For the three months ended December 31, 2015 the electric distribution systems' usage totalled 356.1 GW-hrs, as compared to 365.4 GW-hrs for the same period in 2014, a decrease of 9.3 GW-hrs.

Natural Gas Distribution Systems	Three months ended December 31,	
	2015	2014
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	248,000
Commercial and Industrial	**27,000**	27,000
Total Average Active Natural Gas Connections For The Period	**275,000**	275,000
Customer Usage (MMBTU)		
Residential	**3,002,000**	3,918,000
Commercial and Industrial	**2,362,000**	2,885,000
Total Customer Usage (MMBTU)	**5,364,000**	6,803,000

For the three months ended December 31, 2015, usage at the natural gas distribution systems totalled 5,364,000 MMBTU, as compared to 6,803,000 MMBTU during the same period in 2014, a decrease of 1,439,000 MMBTU, or 21.2%. The decrease in natural gas usage, as compared to the same period in 2,014, can primarily be attributed to a lower number of heating degree days experienced in the EnergyNorth and Midstates Gas Systems service territories, as compared to the same period in 2,014.

Water and Wastewater Distribution Systems	Three months ended December 31,	
	2015	2014
Average Active Connections For The Period		
Wastewater connections	**40,000**	40,000
Water distribution connections	**59,000**	58,000
Total Average Active Connections For The Period	**99,000**	98,000
Gallons Provided		
Wastewater treated (millions of gallons)	**532**	535
Water sold (millions of gallons)	**1,971**	1,940
Total Gallons Provided	**2,503**	2,475

During the three months ended December 31, 2015, the water and wastewater distribution systems provided approximately 1,971 million gallons of water to its customers and treated approximately 532 million gallons of wastewater, which was relatively consistent with 1,940 million gallons of water provided and 535 million gallons of wastewater treated during the same period in 2014.

2015 Distribution Group Operating Results

	Three months ended December 31,		Three months ended December 31,	
	2015 U.S. $ (millions)	2014 U.S. $ (millions)	**2015 Can $ (millions)**	2014 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**40.8**	47.8	**54.6**	54.4
Less: Cost of Sales – Electricity	**(23.1)**	(29.9)	**(30.9)**	(34.2)
Net Utility Sales - Electricity	**$ 17.7**	$ 17.9	**$ 23.7**	$ 20.2
Utility natural gas sales and distribution	**80.1**	102.5	**107.5**	116.7
Less: Cost of Sales – Natural Gas	**(36.4)**	(65.6)	**(48.9)**	(74.8)
Net Utility Sales - Natural Gas	**$ 43.7**	$ 36.9	**$ 58.6**	$ 41.9
Net Utility Sales - Water Distribution & Wastewater Treatment	**15.3**	15.0	**20.4**	18.6
Gas Transportation	**5.7**	6.8	**7.6**	7.6
Other Revenue	**0.1**	3.0	**0.2**	3.4
Net Utility Sales	**$ 82.5**	$ 79.6	**$ 110.5**	$ 91.7
Operating expenses	**(39.2)**	(39.8)	**(52.3)**	(46.0)
Other income	**0.8**	0.8	**1.1**	0.9
Distribution Group operating profit	**$ 44.1**	$ 40.6	**$ 59.3**	$ 46.6

2015 Fourth Quarter Operating Results

For the three months ended December 31, 2015, the Distribution Group reported an operating profit of U.S. $44.1 million, as compared to U.S. $40.6 million for the comparable period in the prior year. The increase is primarily due to implementation of final rates at the EnergyNorth, Missouri, and Illinois Gas Systems. Measured in Canadian dollars, the group's operating profit was $59.3 million, as compared to $46.6 million during the same period in 2014, which represents an increase of $12.7 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, 2015
Prior Period Operating Profit	$	**46.6**
Existing Facilities		
Electric Distribution Systems: The decrease in net utility sales at the Granite State Electric System is due to decreased GW-hrs used by commercial customers as compared to the same period in the previous year, partially offset by an increase in net utility sales at the Calpeco Electric System for a revenue component that is not included in the decoupling mechanism.		(0.2)
Natural Gas Distribution Systems: Primarily due to increased revenues at the New England Gas System as a result of tracking mechanisms.		3.2
Water Distribution & Wastewater Treatment Systems: The water utilities' performance, excluding rate case impacts, was in line with the prior year.		—
Other Income: Decrease is primarily due to reduced billings for contracted services as compared to the same period in 2014.		(2.8)
		0.2
Rate Cases		
Natural Gas Distribution Systems: Successful implementation of new rates at the EnergyNorth and the Missouri Natural Gas System.		3.3
Water Distribution & Wastewater Treatment Systems: Successful implementation of new rates at the LPSCo Water System.		0.2
		3.5
Foreign Exchange		
Increased operating profit as a result of a stronger U.S. dollar.		**9.0**
Current Period Operating Profit	$	**59.3**

2015 Twelve Month Usage Results

Electric Distribution Systems

	Twelve months ended December 31	
	2015	2014
Average Active Electric Connections For The Period		
Residential	**80,000**	79,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**92,000**	91,000
Customer Usage (GW-hrs)		
Residential	**554.9**	557.4
Commercial and Industrial	**898.7**	933.4
Total Customer Usage (GW-hrs)	**1,453.6**	1,490.8

For the twelve months ended December 31, 2015 the electric distribution systems' usage totalled 1,453.6 GW-hrs, as compared to 1,490.8 GW-hrs for the same period in 2014, a decrease of 37.2 GW-hrs.

Natural Gas Distribution Systems

	Twelve months ended December 31	
	2015	2014
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	248,000
Commercial and Industrial	**27,000**	26,000
Total Average Active Natural Gas Connections For The Period	**275,000**	274,000
Customer Usage (MMBTU)		
Residential	**17,385,000**	18,915,000
Commercial and Industrial	**12,460,000**	12,673,000
Total Customer Usage (MMBTU)	**29,845,000**	31,588,000

For the twelve months ended December 31, 2015, usage at the natural gas distribution systems totalled 29,845,000 MMBTU, as compared to 31,588,000 MMBTU during the same period in 2014, a decrease of 1,743,000 MMBTU, or 5.5%. The decrease in natural gas usage, as compared to the same period in 2014, can be primarily attributed to a decrease in heating degrees days experienced in the EnergyNorth and Midstates Gas Systems service territories as compared to 2014.

Water and Wastewater Distribution Systems

	Twelve months ended December 31,	
	2015	2014
Average Active Connections For The Period		
Wastewater connections	**40,000**	39,000
Water distribution connections	**59,000**	58,000
Total Average Active Connections For The Period	**99,000**	97,000
Gallons Provided		
Wastewater treated (millions of gallons)	**2,168**	2,127
Water sold (millions of gallons)	**8,457**	8,310
Total Gallons Provided	**10,625**	10,437

During the twelve months ended December 31, 2015, the water and wastewater distribution systems provided approximately 8,457 million gallons of water to its customers and treated approximately 2,168 million gallons of wastewater, as compared to 8,310 million gallons of water and 2,127 million gallons of wastewater during the same period in 2014. The increase in water sold can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014. The increase in wastewater treated is primarily attributed to an increase in wastewater treated at our sewer utilities located in the state of Arizona.

2015 Twelve Month Operating Results

	Twelve months ended December 31,		Twelve months ended December 31,	
	2015 U.S. $ (millions)	2014 U.S. $ (millions)	**2015 Can $ (millions)**	2014 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**175.6**	185.1	**224.1**	204.7
Less: Cost of Sales – Electricity	**(103.3)**	(108.8)	**(131.6)**	(120.5)
Net Utility Sales - Electricity	**$ 72.3**	$ 76.3	**$ 92.5**	$ 84.2
Utility natural gas sales and distribution	**339.9**	378.2	**431.3**	419.9
Less: Cost of Sales – Natural Gas	**(172.0)**	(234.8)	**(217.3)**	(261.1)
Net Utility Sales - Natural Gas	**$ 167.9**	$ 143.4	**$ 214.0**	$ 158.8
Net Utility Sales - Water Distribution & Wastewater Treatment	**61.3**	58.8	**78.4**	66.4
Gas Transportation	**26.4**	23.5	**33.5**	26.1
Other Revenue	**12.1**	5.1	**15.8**	5.7
Net Utility Sales	**$ 340.0**	$ 307.1	**$ 434.2**	$ 341.2
Operating expenses	**(168.3)**	(160.7)	**(213.8)**	(178.2)
Other income	**3.2**	2.9	**4.0**	3.4
Distribution Group operating profit	**$ 174.9**	$ 149.3	**$ 224.4**	$ 166.4

For the twelve months ended December 31, 2015, the Distribution Group reported an operating profit of U.S. $174.9 million, as compared to U.S. $149.3 million for the comparable period in the prior year. The increase is primarily due to the implementation of higher rates as a result of successful rate cases at the EnergyNorth, Missouri, Illinois, and Peach State Gas Systems, and revenues from contracted services as compared to the same period in 2014. Measured in Canadian dollars, the group's operating profit was $224.4 million, as compared to $166.4 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve months ended December 31, 2015
Prior Period Operating Profit	**$**	**166.4**
Existing Facilities		
Electric Distribution Systems: lower demand at Granite State Electric System and increased operating expenses at the Calpeco Electric System pertaining to rate case administration		(3.0)
Natural Gas Distribution Systems: increase in transportation revenues		3.3
Water Distribution & Wastewater Treatment Systems: increased operating costs at the water and wastewater facilities		(0.3)
Other Income: increased billings for contracted services as compared to the same period in 2014		7.0
		7.0
New Facilities		
Water & Wastewater Distribution and Treatment Systems: Acquisition of the White Hall Water and Wastewater System		0.5
Other Income		0.2
		0.7
Rate Cases		
Electric Distribution Systems: In 2014 the Granite State Electric System retroactively recognized rates pertaining to its 2014 rate case settlement. A similar adjustment was not made in 2015.		(2.4)
Natural Gas Distribution Systems: Successful implementation of new rates at the EnergyNorth, Illinois, Georgia and the Missouri Natural Gas Systems		19.9
Water Distribution & Wastewater Treatment Systems: Successful implementation of new rates at the LPSCo Water System		1.3
		18.8
Foreign Exchange		
Increased operating profit as a result of a stronger U.S. dollar.		**31.5**
Current Period Operating Profit	**$**	**224.4**

Regulatory Proceedings

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

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Illinois Gas System	Illinois	General Rate Case	$5.7	Final Order issued in February 2015 approving a U.S. $4.6 million rate increase effective February 2015.
Pine Bluff Water System	Arkansas	General Rate Case	$2.5	Final Order issued in March 2015 approving a U.S. $1.1 million rate increase effective March 15, 2015.
EnergyNorth System	New Hampshire	General Rate Case	$16.1	Application filed August 2014; a temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim increase effective December 1, 2014 retroactive to November 1, 2014 upon approval of permanent rates. A final permanent rate decision was issued June 2015, allowing for a U.S. $12.4 million rate increase effective July 1, 2015.
Peach State Gas System	Georgia	GRAM	$3.4	Application filed on October 2015 seeking a U.S. $3.4 million revenue increase. Commission approval was received in February 2016, allowing for 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 effective March 2016.
Pending Rate Cases				
CalPeco Electric System	California	General Rate Case	$13.6	Application filed in May 2015 seeking a U.S. $13.6 million revenue increase effective January 2016. A final permanent rate decision is expected in Q2 2016.
Black Mountain Sewer System	Arizona	General Rate Case	$0.4	Application filed in June 2015 seeking a U.S. $0.4 million revenue increase. A final permanent rate decision is expected in Q3 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 is expected in Q4 2016.
Bella Vista Water System	Arizona	General Rate Case	$1.6	Application filed in October 2015 seeking a U.S. $1.6 million revenue increase. A final permanent rate decision is expected in Q4 2016.

Completed Rate Cases

On March 31, 2014, the Midstates Gas System filed a rate case with the Illinois Commerce Commission ("ICC") seeking an increase in revenue of U.S. $5.7 million. The filing was based on a test year that includes anticipated capital expenditures within 2014 and 2015. An Order was issued on February 11, 2015, approving a U.S. $4.6 million revenue increase effective February 20, 2015.

On July 2, 2014, Pine Bluff Water System filed an application with the Arkansas Public Service Commission ("APSC") seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. An Order was issued on March 12, 2015, approving a U.S. $1.1 million revenue increase effective March 15, 2015.

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. A temporary rate increase was approved on November 21, 2014, allowing a U.S. $7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates. On June 26, 2015, an Order was issued approving a settlement agreement allowing for a U.S. $12.4 million revenue increase effective July 1, 2015.

On October 1, 2015, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.4 million in its annual GRAM filing with the Georgia Public Service Commission. New rates were to be effective February 1, 2016, for the period February 1, 2016, through January 31, 2017 to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 2015 (historic test year), with adjustments for the 12 months ending September 2016 (forward looking test year). Commission approval was received in February 2016, allowing for a U.S. $2.7 million rate increase effective March 1, 2016. The difference from the original proposed amount was due to tax depreciation rates and the use of revised inflationary factors applied to operating expenses.

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

Pending Rate Cases and Other Applications of Note

On May 1, 2015, the CalPeco Electric System filed an application with the California Public Utilities Commission ("CPUC") seeking an increase in revenue of U.S. $13.6 million, or 17.3%, based on a test year ending December 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The increase reflects a requested return on equity of 10.5% and a debt/equity structure of 45%/55%. The previous test year ended December 31, 2011. A final permanent rate decision is expected in the second quarter of 2016, however, new permanent rates are proposed to be retroactively effective in the first quarter of 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 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 final decision and implementation of new rates is expected for the third quarter of 2016.

On October 28, 2015, the Rio Rico Water and Wastewater System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, 10.8% ROE, and 70% equity, for an overall rate of return of 8.6%. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the fair value Arizona rate evaluation model ("FARE"), a purchased power adjuster mechanism ("PPAM") and a property tax adjuster mechanism ("PTAM"). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending February 2012.

On October 28, 2015, the Bella Vista Water System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $1.6 million, or 33.6%, based on a test year ending December 31, 2014, a rate base of U.S. $13.2 million, 11.6% ROE, and 70% equity, for an overall rate of return of 9.16%. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the FARE, a PPAM and a PTAM. A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending March 2009.

Other Applications

In April 2014, the CalPeco Electric System filed an application with the CPUC seeking to recover U.S. $2.1 million recorded within its Vegetation Management Memorandum Account ("VMMA") during the period May 2012 through December 2012. A proposed decision was issued in September 2015 supporting 100% recovery of the VMMA costs. This was followed by an Order from the CPUC on October 22, 2015 supporting the cost recovery.

Related to the above CalPeco Electric System rate application are two additional applications in California. The first is an Application filed with the CPUC on April 17, 2015 for the issuance of a Certificate of Public Convenience and Necessity ("CPCN") to acquire, own and operate a solar power generation station with a total generation capacity of up to 60MW (the "Solar Project"). The application requested authorization for rate recovery of the costs that the CalPeco Electric System will incur to acquire, own, and operate the Solar Project. The second is an Application filed on April 24, 2015 with the CPUC requesting authority to enter into a new multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV Energy Services Agreement as energy purchase costs. This new PPA is required as an existing PPA with NV Energy expires at the end of 2015. The Distribution Group believes these two applications allow the CalPeco Electric System to continue procurement of its energy supply in a cost-effective manner for its customers and allow the utility to meet its Renewables Portfolio Standard requirements. An Order approving the Solar Application (revised to 50MW in a settlement) was issued in December 2015. An Order approving the new PPA was issued in January 2016.

The EnergyNorth Natural Gas System in New Hampshire recently filed three applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in July 2015 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. This docket is expected to conclude in the second quarter of 2016. A second was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham. This docket is expected to conclude in the second quarter of 2016. A third application was filed in October 2015 to serve the towns of Jaffrey, Rindge, Swanzey, and Winchester. This docket is expected to conclude in the second quarter of 2016.

Park Water System Acquisition Approvals

On September 19, 2014, the Distribution Group announced an agreement to acquire the stock 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. The acquisition closed on January 8, 2016.

An approval application was filed on November 24, 2014, with the CPUC seeking approval for Liberty Utilities Co. to effectively acquire the two water utilities located in California. The CPUC approved a Settlement Agreement supporting the transaction in December 2015. An application was also filed on December 15, 2014, with the Montana Public Service Commission seeking review of the transaction. As regulatory approval for purchase of parent company stock is not expressly required in Montana, the application was withdrawn concurrent with the transaction closing.

TRANSMISSION BUSINESS GROUP

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

Northeast Expansion Pipeline

In November 2014, the Transmission Group announced that it had entered into an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "NEP Project").

Under the agreement, APUC will initially subscribe for a 2.5% interest in NEP Project. APUC also has an opportunity to increase its participation to 10%.

In July 2015, Kinder Morgan announced that it is proceeding with the NEP Project subject to receiving all applicable permits. In late September 2015, the NEP Project (through its developer - Tennessee Gas Pipeline) announced an Open Season designed to attract additional power generation loads in the Northeast. This is in concert with several states which include New Hampshire, Massachusetts and Connecticut moving forward with regulatory initiatives to support the pass through of power generators long term pipeline capacity costs to support further infrastructure development. The commissions for these states have approved the gas distribution utility's contractual commitments to the NEP Project.

Given the proposed route of the project, the Distribution Group will also look to economically expand its gas distribution utility footprint in New Hampshire as well to serve over twenty new communities with natural gas service.

Northeast Supply Pipeline

In December 2015, the Transmission Group announced that it had reached closure in negotiations with subsidiaries of Kinder Morgan to acquire equity investment rights in a new entity ("Northeast Supply Pipeline LLC ("NSP Project")) to undertake the development, construction and ownership of a natural gas transmission pipeline from northeastern Pennsylvania to a point near Wright, New York.

The joint venture could involve a 30 inch diameter, 132-mile greenfield pipeline with a design capacity of up to approximately 1.2 billion cubic feet per day. The project could also include 41 miles of looping of the existing Tennessee 300 Line system in Pennsylvania. The Transmission Group has secured a 4% initial participation right, with additional options to increase its participation to a 10% total ownership interest.

FERC Application

The NEP Project and NSP Project developer, Tennessee Gas Pipeline, filed a combined FERC application for a Certificate of Public Convenience and Necessity along with a complete Environmental Review in November 2015. The estimated project cost for both the NEP Project and NSP Project included in this FERC application was USD $5.2 billion. The total capital investment for the Transmission Group assuming the Company exercises its right to subscribe for 10% of each pipeline project is estimated to be U.S. $520 million. A November 2016 FERC order has been requested and a November 2018 project in service date is planned.

APUC: CORPORATE AND OTHER EXPENSES

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2015**	**2014**	**2015**	**2014**
Corporate and other expenses:				
Administrative expenses	**$ 13.2**	$ 10.5	**$ 40.7**	$ 34.7
(Gain)/Loss on foreign exchange	**0.3**	0.3	**(2.6)**	(1.1)
Interest expense	**17.4**	14.1	**66.0**	62.4
Interest, dividend and other Income[1]	**(2.1)**	(0.5)	**(4.0)**	(3.2)
Write down of long lived assets and loss/(gain) on disposal	**1.1**	0.2	**2.9**	8.0
Acquisition-related costs	**0.5**	1.6	**1.8**	2.6
(Gain)/Loss on derivative financial instruments	**—**	2.0	**(2.2)**	1.4
Income tax expense	**11.8**	3.7	**43.7**	16.8

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

2015 Annual Corporate and Other Expenses

During the year ended December 31, 2015, administrative expenses totalled $40.7 million, as compared to $34.7 million in the same period in 2014. The $6.0 million 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 year ended December 31, 2015, interest expense totalled $66.0 million, as compared to $62.4 million in the same period in 2014. The increased interest expense is a result of new indebtedness incurred during the first half of 2015 used to partially finance new acquisitions and fund other growth initiatives and a stronger U.S. dollar.

For the year ended December 31, 2015, interest, dividend, equity and other income totalled $4.0 million, as compared to $3.2 million in the same period in 2014, an increase of $0.8 million due to increased dividends from APUC's share investment in the Kirkland Thermal Facility.

For the year ended December 31, 2015, acquisition related costs totalled $1.8 million, as compared to $2.6 million in the same period in 2014. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the year ended December 31, 2015, the gain on derivative financial instruments totalled $2.2 million, as compared to a loss of $1.4 million in the same period in 2014. The increase was primarily driven by derivative gains on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $43.7 million was recorded in the year ended December 31, 2015, as compared to an income tax expense of $16.8 million during the same period in 2014. The increase in income tax expense for the year ended December 31, 2015 is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, a one-time non-cash charge of $2.7 million to deferred income taxes as a result of an arrangement reached with the CRA related to the Unit Exchange Transaction (see Operational Risk Management - Tax Risk and Uncertainty), and other items permanently non-deductible for tax purposes.

2015 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2015, administrative expenses totalled $13.2 million, as compared to $10.5 million in the same period in 2014. The $2.7 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth as well as a stronger U.S. dollar.

For the quarter ended December 31, 2015, interest expense totalled $17.4 million, as compared to $14.1 million in the same period in 2014. The increased interest expense is a result of new indebtedness incurred during the first half of 2015 used to partially finance new acquisitions and fund other growth initiatives and a stronger U.S. dollar.

For the quarter ended December 31, 2015, interest, dividend, equity and other income totalled $2.1 million, as compared to $0.5 million in the same period in 2014. The increase in interest, dividend and other income of $1.6 million primarily consists of increased dividends from APUC’s share investment in the Kirkland Thermal Facility.

For the quarter ended December 31, 2015, loss on derivative financial instruments totalled nil, as compared to a loss of $2.0 million in the same period in 2014. The increase was primarily driven by derivative gains on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $11.8 million was recorded in the three months ended December 31, 2015, as compared to an income tax expense of $3.7 million during the same period in 2014. The increase in income tax expense for the quarter ended December 31, 2015 is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, and a stronger U.S. dollar.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

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

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2015**	2014	**2015**	2014
Net earnings attributable to shareholders	**$ 38.0**	$ 31.6	**$ 117.5**	$ 75.7
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**0.6**	0.5	**2.0**	5.0
Loss from discontinued operations, net of tax	**0.1**	1.5	**1.0**	2.1
Income tax expense	**11.8**	3.7	**43.7**	16.8
Interest expense	**17.4**	14.1	**66.0**	62.4
Other losses / (gains)	**(2.1)**	—	**(5.1)**	—
Write-down of long lived assets and loss on disposal	**1.1**	0.2	**2.9**	8.0
Acquisition related costs	**0.5**	1.6	**1.8**	2.6
(Gain) / loss on derivative financial instruments	**—**	2.0	**(2.2)**	1.4
Realized gain / (loss) on energy derivative contracts	**—**	(0.2)	**0.6**	3.6
(Gain) / loss on foreign exchange	**0.3**	0.3	**(2.6)**	(1.1)
Depreciation and amortization	**41.9**	29.0	**149.8**	114.0
Adjusted EBITDA	**$ 109.6**	$ 84.3	**$ 375.4**	$ 290.5

Hypothetical Liquidation at Book Value (“HLBV”) represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2015 amounted to approximately $12.6 million and $33.9 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,		Year ended December 31,	
(all dollar amounts in $ millions)	**2015**	2014	**2015**	2014
Net earnings attributable to shareholders	**$ 38.0**	$ 31.6	**$ 117.5**	$ 75.7
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**0.1**	1.5	**1.0**	2.1
(Gain) / Loss on derivative financial instruments, net of tax	**—**	1.2	**(1.3)**	0.8
Realized gain / (loss) on derivative financial instruments, net of tax	**—**	(0.5)	**(0.8)**	0.7
Write-down long lived assets	**1.1**	0.2	**2.9**	8.0
Deferred tax expense due to CRA agreement related to the Unit Exchange Transaction	**—**	—	**2.7**	—
(Gain) / Loss on foreign exchange, net of tax	**0.2**	0.2	**(1.6)**	(0.7)
Acquisition costs, net of tax	**0.3**	1.0	**1.1**	1.6
Adjusted net earnings	**$ 39.7**	$ 35.2	**$ 121.5**	$ 88.2
Adjusted net earnings per share	**$ 0.15**	$ 0.14	**$ 0.46**	$ 0.37

For the year ended December 31, 2015, adjusted net earnings totalled $121.5 million, as compared to adjusted net earnings of $88.2 million, an increase of $33.3 million as compared to the same period in 2014. The increase in adjusted net earnings for the year ended December 31, 2015 is primarily due to higher income from operations partially offset by higher depreciation and amortization expense as compared to 2014.

For the three months ended December 31, 2015, adjusted net earnings totalled $39.7 million, as compared to adjusted net earnings of $35.2 million, an increase of $4.5 million as compared to the same period in 2014. The increase in adjusted net earnings for the three months ended December 31, 2015 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2014.

Reconciliation of adjusted funds from operations to cash flows from operating activities

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations and Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to adjusted funds from operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to adjusted funds from operations exclusive of these items:

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2015**	2014	**2015**	2014
Cash flows from operating activities	**$ 94.3**	$ 96.5	**$ 261.9**	$ 192.7
Add (deduct):				
Changes in non-cash operating items	**(17.7)**	(33.1)	**11.1**	0.5
Cash used in discontinued operation	**0.1**	0.9	**1.8**	1.7
Production based cash contributions from non-controlling interests	**—**	—	**10.8**	9.0
Acquisition costs	**0.5**	1.6	**1.8**	2.6
Adjusted funds from operations	**$ 77.2**	$ 65.9	**$ 287.4**	$ 206.5
Adjusted funds from operations per share	**0.30**	0.27	**1.15**	0.92

For the year ended December 31, 2015, adjusted funds from operations totalled $287.4 million, as compared to adjusted funds from operations of $206.5 million, an increase of $80.9 million as compared to the same period in 2014.

For the three months ended December 31, 2015, adjusted funds from operations totalled $77.2 million, as compared to adjusted funds from operations of $65.9 million, an increase of $11.3 million as compared to the same period in 2014.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2015**	2014	**2015**	2014
GENERATION GROUP	**$ 4.8**	$ 60.1	**$ 56.0**	$ 201.1
DISTRIBUTION GROUP	**$ 33.7**	$ 77.4	**$ 141.4**	$ 176.8
Corporate	**$ 3.8**	$ 4.3	**$ 6.8**	$ 54.5
Total	**$ 42.3**	$ 141.8	**$ 204.2**	$ 432.4

2015 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2015, the Generation Group incurred capital expenditures of $4.8 million, as compared to $60.1 million during the comparable period in 2014. The capital expenditures primarily relate to continued construction at the Bakersfield II Solar Project, as well as development spending at the Great Bay Solar Project and the Amherst Wind Project, as compared to the prior year which included spend as it related to the completion of the St Damase Wind Facility, and on-going construction of the Morse Wind and Bakersfield I Solar Facilities.

During the three months ended December 31, 2015, the Distribution Group invested $33.7 million (U.S. $29.9 million) in capital expenditures, as compared to $77.4 million (U.S. $68.0 million) during the comparable period in 2014. The Distribution Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to safety and reliability at the gas systems.

2015 Twelve Month Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2015, the Generation Group incurred capital expenditures of $56.0 million, as compared to $201.1 million during the comparable period in 2014. The Generation Group's capital expenditures in 2015 primarily relate to the completion of the Bakersfield I Solar and Morse Wind Facilities, and on-going construction and development expenses related to the Generation Group's development portfolio.

During the twelve months ended December 31, 2015, the Distribution Group invested $141.4 million (U.S. $107.8 million) in capital expenditures, as compared to $176.8 million (U.S. $155.6 million) during the comparable period in 2014. The Distribution Group's capital expenditures primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to safety and reliability at the gas systems.

2016 Capital Investments

The company's consolidated capital investment plan for 2016 is approximately $1,045.0 million, broken down as follows:

(all dollar amounts in $ millions) (U.S. dollar figures translated at the year end exchange rate of $1.3840)		
Generation Group development projects, including joint ventures	$	665.0
Generation Group maintenance capital expenditure program		30.0
Distribution Group rate base investments		270.0
Transmission Group development projects		80.0
Total	**$**	**1,045.0**

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

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C-93), the Generation Group has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine assessments have been submitted to and accepted by the Quebec government. The assessments have identified possible remedial work at seven facilities. Of these seven, remediation work has now been completed at three facilities, monitoring activities are being performed for two facilities, and remedial work is being planned at two facilities.

The Generation Group currently estimates further capital expenditures of approximately $8.0 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

(all dollar amounts in $ millions)		Total	2016	2017	2018	2019
Future Estimated Bill C-93 Capital Expenditures	$	8.0	4.6	2.6	0.5	0.3

The majority of these capital costs are associated with the Belleterre, Rivière-du-Loup, and St. Alban Hydro Facilities.

The Generation Group has been working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Belleterre Hydro Facility that are not required for power generation. During the first quarter of 2015, four dams were declassified and removed from the CEHQ's registry, while three others were reclassified to Class E (Very Low Consequence) dams, from higher classes. Upon the recommendation of third party engineers, the Generation Group is in discussion with the relevant government ministries to postpone the decommissioning work on these dams for five years to allow sufficient time to determine the new decommissioning requirements and develop new project plans.

LIQUIDITY AND CAPITAL RESERVES

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

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its operating groups as at December 31, 2015 under the Facilities:

	As at December 31, 2015				As at Dec 31 2014
(all dollar amounts in $ millions)	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	$ 65.0	$ 441.5	$ 276.8	$ 783.3	$ 647.0
Funds drawn on Facilities	—	(27.3)	—	(27.3)	(47.3)
Letters of Credit issued	(12.9)	(142.6)	(8.8)	(164.3)	(113.8)
Liquidity available under the Facilities	**$ 52.1**	**$ 271.6**	**$ 268.0**	**$ 591.7**	**485.9**
Cash on Hand				124.4	9.3
Total liquidity and capital reserves	**$ 52.1**	**$ 271.6**	**$ 268.0**	**$ 716.1**	**$ 495.2**

On October 30, 2015, the Generation Group entered into a new extendible one year Generation LC Facility. The new facility expands the group's available liquidity by providing for issuances of letters of credit up to a maximum of Cdn. $50 million and U.S. $30 million. Letters of credit in the amount of $80.8 million that were previously issued under the Generation Credit Facility were transferred to the new facility.

As at December 31, 2015, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had $12.9 million of outstanding letters of credit. Subsequent to year end the maturity of the facility was extended by one year. The facility now matures on November 19, 2017 and is subject to customary covenants.

As at December 31, 2015, the $350.0 million Generation Credit Facility had drawn $27.3 million and had $61.9 million in outstanding letters of credit. The facility matures on July 31, 2019.

As at December 31, 2015, the Distribution Group's $276.8 million (U.S.$200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") had drawn $nil and had $8.8 million (U.S. $6.4 million) of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants.

On February 9, 2016, in connection with the acquisition of Empire, the Company obtained a $2.2 billion (U.S. $1.6 billion) in bridge financing commitments from a syndicate of banks. The non-revolving term credit facilities are comprised of a U.S. $1.065 billion debt bridge facility, repayable in full on the first anniversary following its advance, and a U.S. $535.0 million equity bridge facility repayable in full on the first anniversary following its advance. Upon issuing the Debentures (note 25) and receiving the First Instalment, the Company reduced the bridge commitments by $360.0 million (U.S. $263.6 million), as such a total commitment of U.S. $1,336.4 million remains available to the company.

Long Term Debt

On April 30, 2015, the Distribution Group entered into a Note Purchase Agreement for the issuance of U.S. $160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing were used to partially finance the acquisition of the Park Water System and for general corporate purposes. The note was issued in two tranches: U.S. $90.0 million was issued immediately on closing and U.S. $70.0 million was issued on July 15, 2015. The notes have been assigned a rating of BBB High by DBRS. The financing is the fourth series of notes issued pursuant to the company's master indenture.

On October 1, 2015 the Distribution Group repaid the U.S. $9.8 million outstanding under the LPSCo Water System IDA bonds.

On May 12, 2015, the Generation Group repaid, without penalty, U.S. $76.0 million senior project debt of the Shady Oaks Wind Facility.

Subsequent to year end, a subsidiary of the Company entered into a U.S. $235.0 million term credit facility with two U.S. banks. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2017.

As at December 31, 2015, the weighted average tenor of APUC's total long term debt is approximately 9.7 years with an average interest rate of 4.8%.

Convertible Unsecured Subordinated Debentures

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

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

If the Final Installment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of Debentures who have paid the final installment on or before the Final Installment Date will be entitled to receive, on the business day following the Final Installment Date, in addition to the payment of accrued and unpaid interest to and including the Final Installment Date, an amount equal to the interest that would have accrued from the day following the Final Installment Date to and including the first anniversary of the closing of the Debenture Offering had the Debentures remained outstanding and continued to accrue interest until and including such date (the "Make-Whole Payment"). No Make-Whole Payment will be payable if the Final Installment Date occurs on or after the first anniversary of the closing of the Debenture Offering. Prior to the closing of the Acquisition, the Company will at all times have cash on hand or maintain readily available capacity under the revolving credit facilities of not less than the aggregate amount of the first installment paid on the closing of the Debenture Offering and the exercise of the over-allotment option.

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

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

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

Credit Ratings

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

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

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

Contractual Obligations

Information concerning contractual obligations as of December 31, 2015 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
Long-term debt obligations	$	**1,496.1**		8.9		222.8		187.6		1,076.8
Advances in aid of construction	$	**92.2**		1.3		—		—		90.9
Interest on long-term debt obligations	$	**664.0**		74.3		138.8		117.3		333.6
Purchase obligations	$	**243.7**		243.7		—		—		—
Environmental obligation	$	**78.5**		5.4		41.5		1.8		29.8
Derivative financial instruments:										
Cross currency swap	$	**101.6**		4.8		9.0		7.5		80.3
Interest rate swaps	$	**9.7**		—		9.7		—		—
Currency Forward	$	**1.9**		1.9		—		—		—
Energy derivative and commodity contracts	$	**2.1**		1.9		0.2		—		—
Purchased power	$	**309.6**		82.4		108.2		119.0		—
Gas delivery, service and supply agreements	$	**299.7**		66.3		83.3		67.6		82.5
Long term service agreements	$	**701.4**		38.3		73.2		71.7		518.2
Capital projects	$	**43.5**		35.8		7.6		0.1		—
Operating leases	$	**131.8**		5.9		10.2		9.5		106.2
Other obligations	$	**53.5**		12.8		—		—		40.7
Total obligations	$	**4,229.3**	$	**583.7**	$	**704.5**	$	**582.1**	$	**2,359.0**

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2015, APUC had 255,869,419 issued and outstanding common shares.

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

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

At the option of the holders, each Debenture will be convertible into common shares of the Company at any time after the Company acquires Empire, at a conversion price of $10.60 per common share.

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

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2015, APUC had outstanding:

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

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares of APUC. As at December 31, 2015, 24.0 million common shares representing approximately 9% of total shares outstanding had been registered with the Reinvestment Plan and 3,230,697 shares were issued during the year ended December 31, 2015. During the quarter ended December 31, 2015, 997,532 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 15, 2015, an additional 292,337 common shares were issued under the Reinvestment Plan.

Emera shareholdings and subscription receipts

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

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

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

As at March 10, 2016, in total, Emera owns 50,126,766 APUC common shares representing approximately 19.6% of the total outstanding common shares of the Company, and there are 12,024,753 subscription receipts currently held by Emera. APUC believes the issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE BASED COMPENSATION PLANS

For the three and twelve months ended December 31, 2015, APUC recorded $1.7 million and $5.3 million, respectively, in total share-based compensation expense, as compared to $1.1 million and $3.2 million, respectively, for the same period in 2014. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the audited Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2015, total unrecognized compensation costs related to non-vested options and share unit awards were $3.1 million and $1.9 million, respectively, and are expected to be recognized over a period of 1.74 and 1.63 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 year, the Company issued 1,627,525 options to employees of the Company.

As at December 31, 2015, a total of 7,164,652 options are issued and outstanding under the plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs provide for settlement in cash or shares at the election of APUC.

During the year, the Company settled 41,131 vested PSUs. The plan provides for settlement in cash or shares at the election of the Company. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards. During the year, the Company issued 212,250 PSUs to executives and employees of the Company.

As at December 31, 2015, a total of 564,116 PSU's are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards. During the year, the Company issued 47,230 DSUs to the directors of the Company.

As at December 31, 2015, a total of 157,471 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 year, the Company issued 111,355 common shares to employees under the ESPP plan.

As at December 31, 2015, a total of 351,766 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 Directors of APUC is an executive at Emera. During 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. $6.7 million (2014 - U.S. $9.8 million). During 2015, Liberty Utilities purchased natural gas amounting to U.S. $2.3 million (2014 - U.S. $4.0 million) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

There was U.S. $0.5 million included in accruals in 2015 (2014 - $nil) related to these transactions at the end of the periods.

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 $2.0 million (2014 - $0.2 million) during the year.

Senior Executives

As at December 31, 2015, $nil (December 31, 2014 - $0.05 million) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively "Senior Executives").

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership.

The Company terminated the agreement effective June 28, 2015 and paid a usage shortfall fee of $0.01 million. During the year ended December 31, 2015, APUC reimbursed direct costs in connection with the use of the aircraft prior to termination of the block time agreement of $0.5 million (2014 - $0.7 million).

Office Facilities

Until the fourth quarter of 2014 APUC had leased its head office facilities from an entity partially owned by Senior Executives. During the fourth quarter of 2014, APUC terminated the related party lease and moved all head office employees into new premises owned by the Company. Base lease costs for the year ended December 31, 2015 were $nil (2014 - $0.4 million).

Other

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Company. During the year ended December 31, 2015 APUC paid $0.022 million (2014 - $0.2 million) in relation to these services. The spouse is no longer employed by the Company.

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 2016.

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. In 2015, the Risk and Insurance Management Society (RIMS) recognized APUC's enterprise risk management program for achieving sustainable and repeatable ERM practices.

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. Key risks and associated mitigation strategies are reviewed by the Executive Risk Steering Committee on a monthly basis and presented to the Board of Directors on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, security (physical and cyber), 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 matrix to assess impact and likelihood. Financial, reputation and safety implications are 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 plans.

The development and execution of risk treatment plans are actively monitored by the ERM team through a centralized risk register software application. 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 Board audit committee on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Executive Risk Steering Committee, 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 81% of EBITDA in 2015 and 80% 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 $30.6 million ($0.12 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. long term debt to finance its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing cost. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. APUC may from time to time enter into short term foreign currency derivative contracts to hedge exposure of anticipated transactions denominated in a foreign currency.

The cash consideration for the Acquisition of Empire is required to be paid in U.S. dollars, while the Debenture Offering which represents a significant portion of the funds ultimately used to finance the Acquisition, are denominated in Canadian dollars. As a result, increases in the value of the U.S. dollar versus the Canadian dollar prior to payment of the final installment on the Debenture Offering will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Acquisition ultimately obtained by APUC under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Acquisition. To mitigate this risk, the Company has converted the initial amounts received from the Debenture Offering into U.S. dollars. The Company is evaluating the merits of entering into future hedging agreements to mitigate the risk on all or a portion of the remaining funds to be received. Should the Acquisition not close and the Company is required to repay the initial installment received on the Debentures it will have to translate the funds on the initial installment receipt translated into U.S. dollars back to Canadian Dollars.

Market Price Risk

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

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

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

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

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

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge, which commenced on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $1.9 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of about U.S. $1.9 million for the year.

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

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2015, the Generation Group had entered into hedges with a cumulative notional quantity of 10,480 MW-hrs.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on January 1, 2013 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 about U.S. $0.5 million for the year.

Credit/Counterparty Risk

APUC and its subsidiaries are subject to credit risk through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe the credit risk of default by counterparties to its long term power purchase contracts to be significant, as approximately 83.9% of the 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. The following chart sets out the Generation Group's significant customers, their credit ratings and percentage of total revenue associated with the customer:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percent of Revenue
Generation Group - Renewable Energy			
PJM Interconnection LLC	Aa3	$ 40.5	18.2%
Manitoba Hydro	Aa1	29.4	13.2%
Hydro Quebec	Aa2	27.6	12.4%
Pacific Gas and Electric Company	BBB	21.7	9.7%
Ontario Electricity Financial Corporation	Aa2	19.3	8.7%
US Wind Hedge Counterparty	A3	17.9	8.0%
Connecticut Light and Power	Baa1	16.7	7.5%
Commonwealth Edison	Baa1	13.5	6.1%
Total – Generation Group		**$ 186.6**	**83.8%**

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

The remaining revenue of the company is primarily earned by the Distribution Group. In this regard, the credit risk attributed to the Distribution Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $4.6 million which is spread over approximately 104,000 connections, resulting in an average outstanding balance of approximately $40 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $53.8 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $26.9 million. The natural gas and electrical utilities, respectively, derive over 90% and 87% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, the Generation and Distribution Groups utilize derivative instruments as hedges of certain financial risks as discussed elsewhere in this MD&A. APUC is exposed to credit risk related to counterparties to the extent those derivative instruments are in an asset position at a point in time. The company manages counterparty risk by entering into these instruments with counterparties having a credit rating of BBB- or better.

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, 2015. 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 $27.3 million outstanding as at December 31, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.
- The Distribution Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2015. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded into Other Comprehensive Income.

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

Tax Risk and Uncertainty

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

Unit Exchange Transaction

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one for one basis for common shares of Algonquin Power & Utilities Corp (the "Unit Exchange Transaction"). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of $55.6 million on the date of the Unit Exchange Transaction (the "Transaction Date"). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

Earlier in the year APUC received correspondence from the CRA which outlined its intention to challenge the tax consequences of the Unit Exchange Transaction. The CRA was seeking to apply the acquisition of control rules through application of the general anti-avoidance rule of the Income Tax Act (Canada), the effect of which would be to deny APUC the benefit of the tax attributes it assumed as part of the Unit Exchange Transaction.

On June 26, 2015, APUC entered into an agreement with CRA regarding a CRA proposal to reassess APUC's 2009 through 2013 income tax filings in relation to the Unit Exchange Transaction. The agreement resulted in a $16.0 million reduction in APUC's deferred tax assets and a proportional reduction of $13.3 million in deferred credits. Consequently, APUC's results for 2015 reflect a $2.7 million net non-cash charge to deferred income tax expense.

Liquidity Risk

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

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

As at December 31, 2015, APUC and its subsidiaries had a combined $591.7 million of liquidity available under the Facilities remaining and $124.4 million of cash resulting in $716.1 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.3850 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of common share dividends paid during the year ended December 31, 2015, cash provided by operating activities exceeded common share dividends declared by 2.0 times and Adjusted Cash From Operations exceeds common share dividends by 2.2 times.

The current and long term portion of debt totals approximately $1,496.1 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

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

Downgrade in the Company's Credit Rating Risk

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

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.

APUC mitigates this risk by actively monitoring and targeting the key credit metrics and other considerations used by the rating agencies to evaluate its ratings. 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 Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Distribution Groups 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 2016, of which 141,000 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 23,000 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 23,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 73% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $79 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $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 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 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 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.

OPERATIONAL RISK MANAGEMENT

Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Generation Group's hydro assets utilize dams to pond water for generation and if the dams burst potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Generation Group's wind assets could catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions (e.g. El Nina), which will lower wind levels below our PPA and hedge minimum production levels. Production risks associated with the wind turbine generators is mitigated by properly maintaining the units using long term maintenance agreements with the turbine O&M's, which provide for regular inspections and maintenance of property and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Generation Group's Thermal Energy Division uses natural gas and oil, and produce exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the Thermal Energy Division are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged somewhat by long term purchases.

All of the Generation Group's electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Distribution Group's water and wastewater distribution systems operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The Distribution Group's electric distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The Distribution Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (the Generation and Distribution Groups) and geographically (Canada and U.S.), the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance and the establishment of reserves for expenses.

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 Generation Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Distribution 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. As a strategy to mitigate, the Distribution Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expense. 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 Distribution 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 Distribution 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 just and fair compensation be paid to the Distribution Group and the Distribution Group believes such compensation would reflect fair market value for any assets that are taken. Determination of such fair and just 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. In 2014, the Company entered into an agreement to acquire Western Water Holdings LLC, which is the parent company of the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Mountain Water Company is the water utility in Western Montana serving the municipality of Missoula owned by Park Water Company.

Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water. The City's right to take Mountain Water is currently on appeal before the Montana Supreme Court, which is set to hear the appeal on April 22, 2016. If the City of Missoula prevails on appeal and ultimately takes possession of Mountain Water, 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) plus accrued interest and attorney's fees as determined by the Montana court. Mountain Water is seeking U.S. $4.8 million in attorney's fees and U.S. $16.0 million in interest. The City of Missoula opposes an award of attorney's fees and interests as requested by Mountain Water. On December 22, 2015, various developers filed a Petition for Declaratory and Other Relief in Missoula County District Court against Mountain Water and the City of Missoula. The lawsuit pertains to Funded By Others ("FBO") contracts between each developer and Mountain

Water. Under those FBO contracts, the developers paid for facilities to provide water service. Mountain Water agreed to refund those developer advances under the FBO contracts over a 40 year period. These FBO contracts represent a liability of U.S. $22.0 million on the balance sheet of Mountain Water. While there is no allegation of breach by Mountain Water under the FBO contracts, the developers are seeking to enforce these refunds should the utility be transferred to the city. That lawsuit is ongoing and is in the early stages of litigation. In addition, the Montana Public Service Commission ("Montana PSC") has asserted that the indirect change of control of Mountain Water required its approval and is, therefore, investigating potential changes to the rates of Mountain Water. Montana PSC has also expressed an intention to seek penalties against Mountain Water. The Montana PSC has acknowledged that it has no express authority over the acquisition transaction under statute, but has asserted that such authority should be implied. These matters are in the early stages.

On January 8, 2016, the Town of Apple Valley filed an eminent domain complaint against Apple Valley. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases. The first phase will determine the necessity of the taking. The second phase will involve the valuation of the utility assets. If the Town of Apple Valley is successful in the right to take proceeding, a second phase will be held to determine the fair market value of Apple Valley. At present, a trial setting conference has been set for July 7, 2016. The matter is expected to take two to three years to resolve. The condemnation action has potential 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 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.

Acquisition Risk

The risks associated with the Company's acquisition strategy include potential difficulties inherent in acquisitions that may adversely affect the results of an acquisition and these include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions. The Company mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

Completion of the Acquisition of Empire

The Acquisition of Empire is subject to risks that the Acquisition will not close on the terms negotiated (including with respect to the consideration to be paid for the common stock of Empire) or at all, that adverse terms or conditions could be imposed on the Company or Empire in connection with obtaining approvals required to complete the Acquisition, and that completing the Acquisition may not have the expected benefits or may otherwise adversely affect the Company.

The completion of the Acquisition is subject to satisfaction or, in certain cases, waiver of certain conditions. These conditions include approval by the shareholders of Empire, the expiration or termination of the applicable waiting period under the Hart Scott Rodino Act, obtaining clearance from the Committee on Foreign Investment in the United States, and obtaining the approval of each of FERC, the FCC and the State Commissions. In the event that any such regulatory agencies impose unfavourable terms or conditions on the Company or Empire (including requirements to sell assets or limitations on the future conduct of the combined entities), the Company could still be required to complete the transaction on the terms set forth in the acquisition agreement.

Completion of the Acquisition is also subject to the satisfaction or waiver of certain other closing conditions contained in the acquisition agreement, including the absence of any law, judgement or similar governmental action that prevents, makes illegal or prohibits the consummation of the Acquisition.

There is no assurance that the required approvals will be received or that the other closing conditions will be satisfied or waived and, therefore, no assurance that the Company will complete the Acquisition within the expected time frame or at all. The failure to obtain the required approvals within 18 months following entry into the acquisition agreement or to satisfy or waive the other conditions contained in the acquisition agreement may result in the termination of the acquisition agreement.

The Company will be obligated to pay Empire U.S. $65.0 million if the acquisition agreement is terminated by either party due to a failure to obtain the required regulatory approvals within 18 months following execution of the acquisition agreement, or due to a final and non-appealable legal restraint that relates to the required regulatory approvals, or if Empire terminates the acquisition agreement based on a failure by the Company to perform its obligations with respect to obtaining required regulatory approvals, provided that, in each case, at the time of termination the Empire shareholder approval has been obtained and the other conditions to the Company's obligation to complete the Acquisition have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the closing and are then capable of being satisfied, and those conditions that have not been satisfied as a result of a breach of the acquisition agreement by the Company).

In addition, Empire's directors owe fiduciary duties to the Empire shareholders (and other stakeholders), which may require the Empire board to consider competing offers to purchase the stock or assets of Empire. Prior to approval of the Acquisition by Empire's shareholders, the directors of Empire have the right to recommend or accept an alternative offer that the Empire board determines constitutes a superior proposal, provided that before doing so Empire gives the Company an opportunity to negotiate revisions to the acquisition agreement. As a result, receipt by Empire of a superior proposal could result in an increase in the cash purchase price for the Acquisition or other revisions to the terms and conditions of the Acquisition or, alternatively, the termination of the acquisition agreement.

A termination of the acquisition agreement may have a negative effect on the price of the Installment Receipts, the Debentures and the Common Shares and will result in the redemption of the Debentures. In addition, if the closing of the Acquisition does not take place as contemplated, the Company could suffer other adverse consequences, including the loss of investor confidence.

For the purpose of financing the Acquisition, the Company obtained Acquisition Credit Facilities of $2.2 billion (U.S. $1.6 billion) in February 2016, and completed the $1.15 billion Debentures Offering in March 2016, including the exercise of an over-allotment. On March 9, 2016, upon issuing the Debentures (see Financial Statements note 25) and receiving the First Instalment, the Company reduced the aggregate commitments under the Acquisition Credit Facilities by $360.0 million (U.S. $263.6 million).

The Company expects to fund the cash purchase price of the Acquisition and the acquisition-related expenses with a combination of some or all of the following: (i) net proceeds of the first instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Acquisition Credit Facilities; and (iv) existing cash on hand and other sources available to the Corporation.

The commitment of the lenders to enter into the Acquisition Credit Facilities is subject to certain standard conditions which may result in such facilities becoming unavailable to the Company in certain circumstances. There is no guarantee that alternate sources of funding will be available to the Company or its affiliates at the desired time or at all, or on cost-efficient terms.

If the Acquisition Credit Facilities become unavailable to the Company, and the Company fails to obtain sufficient alternative financing, the Company may not be able to complete the Acquisition. The Company's obligation to complete the Acquisition is not conditional on the Company obtaining financing on favourable terms or at all. In the event that the Company does not have sufficient financing to complete the Acquisition, upon satisfaction of all conditions to closing, and Empire terminates the acquisition agreement as a result, the Company will be obligated to pay Empire U.S. $65.0 million, in addition to potential liability for damages.

If a material amount of the final instalment for the Debentures is not paid by holders of Instalment Receipts and the Company is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final instalment, the Company will not be able to use those proceeds to repay the Acquisition Credit Facilities. The foregoing, or any other inability to obtain alternate sources of funding to fund the Acquisition or replace the Acquisition Credit Facilities, may have a negative impact on the consolidated capitalization of the Company until such time as the Acquisition Credit Facilities have been repaid by the Company in full, and may negatively impact the financial performance of the Company, including the extent to which the Acquisition is accretive.

In addition, any movement in interest rates that could affect the underlying cost of these instruments may affect the expected accretion of the Acquisition. The Company may enter into hedging arrangements to mitigate this risk.

As a result of the pursuit and completion of the Empire acquisition, significant demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the acquisition. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Although the acquisition agreement contains covenants on the part of Empire regarding the operation of its business prior to closing the Acquisition, the Company will not control Empire and its subsidiaries until completion of the Acquisition and Empire's business and results of operations may be adversely affected by events that are outside of the Corporation's control during the intervening period. Historic and current performance of Empire's business and operations may not be indicative of success in future periods. The future performance of Empire may be influenced by, among other factors, weather, economic downturns, increased environmental regulation, turmoil in financial markets, unfavourable regulatory decisions, rising interest rates and other factors beyond the Corporation's control. As a result of any one or more of these factors, among others, the operations and financial performance of Empire may be negatively affected which may adversely affect the future financial results of the Company.

The Company expects to incur a number of costs associated with completing the Acquisition. The substantial majority of these costs will be non-recurring expenses and will consist of transaction costs related to the Acquisition, including costs relating to the financing of the Acquisition and obtaining regulatory approval. Additional unanticipated costs may be incurred and the amounts may be material.

Although the Company has conducted what it believes to be a prudent and thorough level of investigation in connection with the Acquisition, an unavoidable level of risk remains regarding the accuracy and completeness of such information. While the Company has no reason to believe the information obtained from Empire or taken from the public disclosure record is misleading, untrue or incomplete, the Company cannot assure the accuracy or completeness of such information nor can the

Company compel Empire to disclose events which may have occurred or may affect the completeness or accuracy of such information but which are unknown to the Company.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases, and other agreements, the probability of the agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

The Distribution Group's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Distribution Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Distribution Group expects to be allowed to earn a return on such investment.

In conjunction with recent acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when 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.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation, and utilities business segments, which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of an adequate insurance program, which includes property, equipment breakdown, environmental, and liability policies.

The Generation Group's ongoing operations and historic activities are subject to various environmental laws and regulations and are regulated by federal agencies such as the United States Environmental Protection Agency, FERC, NERC, Environment Canada, Fisheries and Oceans Canada; and State/Provincial Agencies, such as the New York State Department of Environmental Conservation ("NYSDEC"), California Air Resource Board, Connecticut Department of Environmental Protection ("CDEP"), Illinois Department of Environmental Protection ("IDEP'), Pennsylvania Game Commission ("PGC"), Alberta Environment, Manitoba Conservation, Ontario Ministry of the Environment, Ontario Ministry of Natural Resources, among others. Power generation facilities generate air emissions, noise, potential for flooding, spill risk, possible disruption of protected wildlife, along with the generation of industrial wastewater and certain amounts of hazardous wastes.

The Distribution Group faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, the Distribution Group generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, the Generation and Distribution Groups investigate promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

The primary risks associated with the operation of gas distribution systems are related to uncontrolled natural gas releases, equipment damage by construction equipment/third parties or severe weather events. The gas distribution assets are regulated by the Pipeline Hazardous Material Safety Administration (PHMSA) under the United States Department of Transportation and their respective State regulations in which the assets are located. Natural Gas Distribution Systems are subject to detailed inspections by State Regulatory Agencies to ensure adherence to applicable regulations. State Regulator Agencies review the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. The Distribution Group monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

The primary risks associated with the operation of power generation facilities are related to uncontrolled contaminant releases (or above the permitted limits), not being in continued compliance with permits and licenses obligations such as, continuous emissions monitoring, periodic reporting/source testing, general performance/operating conditions, operations adjustments (wind projects) resulting from post construction wildlife mortality monitoring, dam safety, potential accidental release of mineral oil or other hazardous materials to the environment.

The Distribution Group's ongoing operations and historic activities are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services ("NHDES"). Similar to other industrial companies, the gas and electric distribution utilities generate certain hazardous wastes. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by the Distribution Group, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System 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 Distribution Group is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the NHDES. The Distribution Group believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental cleanup activities will be $78.5 million which, at discount rates ranging from 2.5% to 4.2%, represents $71.5 million on a discounted basis, as the Distribution Group's estimate of costs for known issues that has been accrued at December 31, 2015. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2015 the Company has reflected a regulatory asset of $116.7 million for the remediation of the MGP and related sites.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable.

Cycles and Seasonality

Generation Group

The 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 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 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.

Distribution Group

The Distribution 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 Distribution Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Distribution 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 to revenues.

The Distribution 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 Distribution Group operates have approved mechanisms to mitigate demand fluctuations.

Development and Construction Risk

The Generation Group actively engages in the development and construction of new power generation facilities. The current pipeline of projects either currently in construction or in development is $1.8 billion and are mainly renewable solar and wind projects. 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. Examples of inherent risks pertaining to power generation facility development can include: technical issues with the interconnection utility, unfavorable permitting results or delays emanating from State, Provincial or Federal agency interface, construction delays or cost overruns, equipment performance outside of expectations, and land owner disputes. The Generation Group mitigates these risk through its due diligence processes, sound project management principals and appropriate contingency plans and reserves.

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 Generation Group 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.

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 Amherst Wind Project in Ontario is currently the subject of an appeal to the ERT for which a decision is expected in April 2016. If the ERT finds that the project will cause serious and irreversible harm to the environment or human health, the tribunal has the authority to revoke the provincial environmental permit. If the ERT has concerns, the project would expect to be given the opportunity to make submissions or changes to the project to address the tribunals concerns.

Obligations to Serve

The Distribution Group may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, the Distribution Group may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Litigation Risks and Other Contingencies

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

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against various Algonquin entities in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Algonquin entities and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). Over the past 16 years there have been various legal proceedings and appeals in connection with this matter. Both the Algonquin entities and Trafalgar had certain motions before the Bankruptcy Court seeking determinations on a number of matters. On November 13, 2015, the Bankruptcy Court entered judgment that: (1) grants Algonquin's motion for summary judgment; (2) denies Trafalgar's' motion for summary judgment; and (3) dismisses Trafalgar's Adversary Complaint on the merits. Trafalgar has appealed the Judgment. Trafalgar has brought a motion for reconsideration of this judgment.

Additionally, Trafalgar has alleged in various pleadings before the Bankruptcy Court that the Algonquin entities has mismanaged the operations of the Trafalgar Hydro Facilities (now sold as noted below) under that certain Management Agreement dated January 15, 1996. No demand has been made based on these allegations. Any such claims are subject to an arbitration clause under the Management Agreement. Algonquin denies any liability under either the 1995 agreement or the Management Agreement and will continue to vigorously defend against these claims.

The Bankruptcy Court has approved the sale of all seven of the Trafalgar Hydro Facilities all of which have now been closed. The parties are attempting to settle this long standing lawsuit through mediation.

Long Sault global adjustment claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011, onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court's judgment of March 12, 2015. The appeal was heard on December 14 and December 15, 2015; the Court has reserved judgment.

Côte Ste-Catherine Water Lease Dues

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

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6.8 million. In 2012, the Company paid an amount of $1.9 million to the Government of Quebec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2015:

(all dollar amounts in $ millions except per share information)	1st Quarter 2015	2nd Quarter 2015	3rd Quarter 2015	4th Quarter 2015
Revenue	$ 381.9	$ 196.2	$ 189.6	$ 260.3
Adjusted EBITDA	114.5	81.1	70.2	109.6
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	42.5	22.2	17.3	39.7
Adjust net earnings per share	0.17	0.08	0.06	0.15
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
	1st Quarter 2014	2nd Quarter 2014	3rd Quarter 2014	4th Quarter 2014
Revenue	$ 343.0	$ 188.6	$ 151.6	$ 259.3
Adjusted EBITDA	97.5	66.4	41.4	84.3
Net earnings / (loss) attributable to shareholders from continuing operations	35.6	15.3	(6.1)	33.1
Net earnings/(loss) attributable to shareholders	35.9	14.6	(6.3)	31.6
Net earnings / (loss) per share from continuing operations	0.16	0.06	(0.04)	0.13
Net earnings/(loss) per share	0.17	0.06	(0.04)	0.13
Adjusted net earnings	36.8	16.6	(0.4)	35.2
Adjust net earnings per share	0.17	0.07	(0.01)	0.14
Total Assets	3,644.3	3,553.6	3,799.3	4,105.1
Long term debt[1]	1,400.9	1,381.0	1,404.3	1,271.7
Dividend declared per common share	0.09	0.09	0.10	0.10

1 Long term debt includes current and long term portion of debt

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

Quarterly revenues have fluctuated between $151.6 million and $381.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $43.1 million and a net loss of $6.3 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

DISCLOSURE CONTROLS

At the end of the fiscal year ended December 31, 2015, 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, 2015, 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, 2015, 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. On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) published an updated Internal Control - Integrated Framework (2013) and related illustrative documents. The company adopted the new framework in 2014.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2015 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, 2015.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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 are discussed in Note 1 to the consolidated financial statements. 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.

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.

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 Distribution 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 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-2015) recently released by the Society of Actuaries adjusted to reflect the 2015 Social Security Administration ultimate improvement rates.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2015 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.

(all dollar amounts in $ millions)	2015 OPEB Plans Accumulated Postretirement Benefit Obligation	2015 OPEB Plans Net Periodic Postretirement Benefit Cost	2015 Pension Plans Accrued Benefit Obligation	2015 Pension Plans Net Periodic Pension Cost
Discount Rate				
1% increase	(9.6)	(1.2)	(26.6)	(1.2)
1% decrease	12.1	1.3	32.6	3.5
Future compensation rate				
1% increase	—	—	0.2	1.3
1% decrease	—	—	(0.2)	(0.9)
Expected return on plan assets				
1% increase	—	(0.1)	—	(1.8)
1% decrease	—	0.1	—	1.8
Life expectancy				
1% increase	6.7	1.0	17.8	2.8
1% decrease	(6.2)	(1.0)	(19.3)	(2.0)
Health care trend				
1% increase	10.8	2.0	—	—
1% decrease	(8.7)	(1.7)	—	—

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. A significant change in estimate could affect APUC's results of operations.

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, 2015, 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, 2015.

March 10, 2016

Chief Executive Officer

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, 2015 and 2014 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, 2015, 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 U.S. 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 audit 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, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2015, in conformity with U.S. 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, 2015, 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, 2016 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, 2016

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, 2015, 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.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, 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, 2015 and 2014, 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, 2015 and our report dated March 10, 2016 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants,

Licensed Public Accountants

Toronto, Canada

March 10, 2016

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 124,353	$ 9,273
Accounts receivable, net (note 4)	186,681	188,573
Natural gas in storage (note 1(h))	28,502	31,550
Regulatory assets (note 7)	32,213	61,645
Prepaid expenses	18,409	10,431
Derivative instruments (note 24)	15,039	10,688
Other current assets	18,537	15,359
	423,734	327,519
Property, plant and equipment, net (note 5)	3,873,684	3,278,422
Intangible assets, net (note 6)	77,963	54,011
Goodwill (note 6)	110,493	92,328
Regulatory assets (note 7)	213,102	185,627
Derivative instruments (note 24)	73,322	31,782
Long-term investments (note 8)	174,802	43,279
Deferred income taxes (note 19)	18,109	64,275
Other assets (note 12)	26,516	25,605
	$ 4,991,725	$ 4,102,848

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 50,428	$ 68,540
Accrued liabilities	193,320	199,374
Dividends payable (note 16)	41,802	25,395
Regulatory liabilities (note 7)	44,167	20,590
Long-term debt (note 9)	8,945	9,130
Other long-term liabilities and deferred credits (note 13)	36,621	49,303
Other liabilities	16,593	10,234
	391,876	382,566
Long-term debt (note 9)	1,477,850	1,262,589
Regulatory liabilities (note 7)	131,180	101,166
Deferred income taxes (note 19)	175,799	134,460
Derivative instruments (note 24)	106,628	40,088
Pension and other post-employment benefits (note 10)	150,094	138,602
Other long-term liabilities (note 13)	223,135	177,235
Preferred shares, Series C (note 11)	17,548	17,608
	2,282,234	1,871,748
Redeemable non-controlling interest (note 3(e))	25,751	12,146
Equity:		
Preferred shares (note 14(b))	213,805	213,805
Common shares (note 14(a))	1,808,894	1,633,262
Subscription receipts (note 14(a)(ii))	110,503	110,503
Additional paid-in capital	38,241	33,068
Deficit	(523,116)	(505,305)
Accumulated other comprehensive income (note 15)	286,737	34,213
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,935,064	1,519,546
Non-controlling interests	356,800	316,842
Total Equity	2,291,864	1,836,388
Commitments and contingencies (note 22)		
Subsequent events (notes 3(a) and (b), 8(e), 9, 14(a)(iii) and 25)		
	$ 4,991,725	$ 4,102,848

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	
	2015	**2014**
Revenue		
Regulated electricity distribution	$ 224,110	$ 204,721
Regulated gas distribution	464,767	446,025
Regulated water reclamation and distribution	78,467	66,419
Non-regulated energy sales	222,581	202,300
Other revenue	37,930	22,149
	1,027,855	941,614
Expenses		
Operating expenses	278,561	234,038
Regulated electricity purchased	131,647	120,506
Regulated gas purchased	217,236	261,116
Non-regulated energy purchased	27,990	39,264
Administrative expenses	40,675	34,692
Depreciation and amortization	149,806	114,047
Gain on foreign exchange	(2,631)	(1,112)
	843,284	802,551
Operating income from continuing operations	184,571	139,063
Interest expense	65,993	62,418
Interest, dividend, equity and other income	(9,095)	(7,758)
Other gains	(5,110)	—
Acquisition-related costs	1,832	2,552
Write-down of long-lived assets and loss on disposal	2,890	8,027
Loss (gain) on derivative financial instruments (note 24(b)(iv))	(2,188)	1,375
	54,322	66,614
Earnings from continuing operations before income taxes	130,249	72,449
Income tax expense (note 19)		
Current	7,310	3,674
Deferred	36,403	13,133
	43,713	16,807
Earnings from continuing operations	86,536	55,642
Loss from discontinued operations, net of tax	(1,032)	(2,127)
Net earnings	85,504	53,515
Net loss attributable to non-controlling interests (note 18)	(31,976)	(22,186)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 117,480	$ 75,701
Series A and D Preferred shares dividend (note 16)	10,400	9,503
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 107,080	$ 66,198
Basic net earnings per share from continuing operations (note 20)	$ 0.43	$ 0.32
Basic net earnings per share (note 20)	0.42	0.31
Diluted net earnings per share from continuing operations (note 20)	0.42	0.32
Diluted net earnings per share (note 20)	$ 0.42	$ 0.31

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2015	2014
Net earnings	$ 85,504	$ 53,515
Other comprehensive income:		
Foreign currency translation adjustment, net of tax recovery of $nil and $1,049, respectively (notes 1(v), 24(b)(iii) and 24(c))	289,035	104,183
Change in fair value of cash flow hedges', net of tax expense of $12,010 and $6,589, respectively (note 24(b)(ii))	16,165	2,799
Change in unrealized appreciation in value of available-for-sale investments	(73)	1
Change in pension and other post-employment benefits, net of tax expense of $4,923 and tax recovery of $22,446, respectively (note 10)	7,571	(35,669)
Other comprehensive income, net of tax	312,698	71,314
Comprehensive income	398,202	124,829
Comprehensive income attributable to the non-controlling interests	28,198	7,077
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 370,004	$ 117,752

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, 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	—	—	—	—	—	—	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)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	10,815	10,815
Shares issued pursuant to public offering, net of costs (note 14(a)(i))	144,987	—	—	—	—	—	—	144,987
Issuance of common shares under employee share purchase plan	1,343	—	—	(282)	(60)	—	—	1,001
Share-based compensation	—	—	—	5,455	—	—	—	5,455
Balance, December 31, 2015	$1,808,894	$213,805	$ 110,503	$ 38,241	$ (523,116)	$ 286,737	$356,800	$2,291,864

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2014

	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, 2013	$1,351,264	$116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961
Net earnings (loss)	—	—	—	—	75,701	—	(22,186)	53,515
Redeemable non-controlling interests not included in equity	—	—	—	—	—	—	(289)	(289)
Other comprehensive income	—	—	—	—	—	42,051	29,263	71,314
Dividends declared and distributions to non-controlling interests	—	—	—	—	(75,205)	—	(4,738)	(79,943)
Dividends and issuance of shares under dividend reinvestment plan	17,395	—	—	—	(17,395)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	9,934	9,934
Issuance of subscription receipts (note 14(a)(ii))	—	—	110,503	—	—	—	—	110,503
Shares issued pursuant to public offering, net of costs (note 14(a)(i))	263,869	—	—	—	—	—	—	263,869
Issuance of common shares under employee share purchase plan	734	—	—	—	—	—	—	734
Share-based compensation expense	—	—	—	3,203	—	—	—	3,203
Preferred shares, Series D (note 14(b))	—	97,259	—	—	—	—	—	97,259
Acquisition of non-controlling interest (note 18)	—	—	—	22,552	—	23,572	(205,796)	(159,672)
Balance, December 31, 2014	$1,633,262	$213,805	$ 110,503	$ 33,068	$ (505,305)	$ 34,213	$316,842	$1,836,388

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31 2015	2014
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 86,536	$ 55,642
Adjustments and items not affecting cash:		
Depreciation and amortization	151,627	115,399
Deferred taxes	36,403	13,133
Unrealized loss (gain) on derivative financial instruments	(1,990)	3,046
Share-based compensation expense	5,455	3,203
Cost of equity funds used for construction purposes	(2,424)	(1,910)
Pension and post-employment expense	(3,333)	(2,050)
Write-down of long-lived assets	1,781	8,463
Unrealized gain on disposal of VIE	220	—
Increase in deferred income	550	—
Changes in non-cash operating items (note 23)	(11,149)	(1,790)
Changes in non-cash operating items from discontinued operations	—	1,262
Cash used in discontinued operations	(1,806)	(1,682)
	261,870	192,716
Financing Activities		
Cash dividends on common shares	(79,121)	(57,848)
Cash dividends on preferred shares	(10,400)	(9,503)
Cash contributions from non-controlling interests	15,222	11,845
Production-based cash contributions from non-controlling interest	10,815	8,976
Cash distributions to non-controlling interests	(2,936)	(4,738)
Issuance of common shares, net of costs	144,694	261,452
Proceeds from subscription receipts	—	110,503
Issuance of preferred shares, net of costs	—	96,271
Acquisition of non-controlling interest	—	(127,121)
Increase in long-term debt	248,811	236,528
Decrease in long-term debt	(196,149)	(286,552)
Increase in other long-term liabilities	31,544	18,618
Decrease in other long-term liabilities	(6,182)	(3,091)
	156,298	255,340
Investing Activities		
Increase (decrease) in other assets	281	(13,785)
Distributions received in excess of equity income	1,386	264
Receipt of principal on notes receivable	29,273	280
Additions to property, plant and equipment	(204,195)	(432,373)
Acquisitions of long-term investments	(138,560)	(25,432)
Acquisitions of operating entities	(3,717)	(8,757)
Proceeds from sale of long-lived assets	5,516	26,535
	(310,016)	(453,268)
Effect of exchange rate differences on cash	6,928	646
Increase (decrease) in cash and cash equivalents	115,080	(4,566)
Cash and cash equivalents, beginning of year	9,273	13,839
Cash and cash equivalents, end of year	$ 124,353	$ 9,273

Supplemental disclosure of cash flow information:	2015	2014
Cash paid during the year for interest expense	$ 69,610	$ 57,098
Cash paid during the year for income taxes	$ 6,153	$ 2,571
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	$ 44,834	$ 25,568
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 30,645	$ 18,129

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

1. Significant accounting policies

(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.

During the fourth quarter 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.

1. Significant accounting policies (continued)

(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.

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 (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. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash as part of other assets (note 12) 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.

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

1. Significant accounting policies (continued)

(j) Property, plant and equipment

Property, plant and equipment are recorded at cost. Capitalization of development projects begins when management with the relevant authority authorized and has committed to the funding of the 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.

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.

	2015	2014
Interest capitalized on non-regulated property	**$ 1,189**	$ 3,584
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,657**	1,577
Allowance for equity funds	**2,425**	1,910
Total	**$ 5,271**	$ 7,071

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.

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

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

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	
	2015	2014	2015	2014
Generation Group	**3 - 60**	3 - 60	**32**	35
Distribution Group	**5 - 100**	5 - 100	**42**	40
Equipment	**5 - 50**	5 - 50	**14**	14

Effective January 1, 2015, the Company changed the depreciation method from the straight-line method to 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.

This change in the depreciation method results from having better information on the consumption of the benefits of certain individual components that are directly related to production and separately identified in the records of the Company. The change is being recognized prospectively.The impact of the change on the operating results for 2015 was a reduction of depreciation expense of $3,418. The impact on basic and diluted net earnings per share for 2015 was an increase of $0.01. The change is not expected to materially affect net earnings or net earnings per share on an annual basis.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Distribution 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.

1. Significant accounting policies (continued)

(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(a) and (b)).

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 $104,243 (2014 - $112,344) and $62,138 (2014 - $59,449), 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 $18,651 (2014 - $11,218), operating expenses and amortization of $5,645 (2014 - $3,418) and interest expense of $4,407 (2014 - $3,820).

(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.

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.

(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.

1. Significant accounting policies (continued)

(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 and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units") which 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 Hypothetical Liquidation at Book Value ("HLBV") method of accounting. The HLBV method uses a balance sheet approach, which measures the allocation of income or loss of the Class A partnership units in each period by calculating the change in the amount of distribution the partners would contractually be entitled to based on a hypothetical liquidation of the book value carrying amounts of the entity at the beginning of a reporting period compared to the end of that period (note 18).

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.

1. Significant accounting policies (continued)

(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.

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 the Company's Calpeco Electric System, Peach State Gas System and New England Gas System is subject to a revenue decoupling mechanism approved by their respective regulator 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.

During the year, the Company settled insurance claims for business interruption at some of its generation facilities under repairs and as a result recognized revenue of $581 (2014 - $1,227).

(s) Foreign currency translation

The Company'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.

1. Significant accounting policies (continued)

(t) Income taxes (continued)

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 in 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.

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.

1. Significant accounting policies (continued)

(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, and 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 2015-17 Income Taxes (Topic 740) to simplify the presentation of deferred income taxes. This ASU requires that deferred tax liabilities and assets be classified as non-current in a classified statement of financial position. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by this ASU. The Company retrospectively adopted this ASU in the fourth quarter of 2015. As a result, a deferred tax asset and a deferred tax liability of $7,210 and $3,702, respectively, that were presented as current as of December 31, 2014 have been reclassified to non-current deferred tax asset and deferred tax liability on the consolidated balance sheets.

The FASB issued ASU 2015-13 Derivatives and Hedging (Topic 815): Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets. This ASU clarifies that the use of locational marginal pricing by an independent system operator does not constitute net settlement of a contract for the purchase or sale of electricity on a forward basis that necessitates transmission through, or delivery to a location within, a nodal energy market. Consequently, the use of locational marginal pricing by the independent system operator does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. The adoption of this ASU in the third quarter of 2015 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2015-10, 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 second quarter of 2015 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2015-04, Compensation: Retirement Benefits (Subtopic 715), to provide a practical expedient that permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end or significant event. The Company adopted this ASU prospectively in the second quarter of 2015 and as a result, remeasured amendments to its pension plans, made during the second quarter, using the month-end closest to the amendments.

The FASB issued ASU 2015-03, Interest: Imputation of Interest (Subtopic 835-30), to simplify presentation of debt issuance costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected. Effective January 1, 2015, the Company applied this ASU retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs of $8,304 as of December 31, 2014 that were previously presented as other assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term debt. In accordance with ASU 2015-15 Interest: Imputation of Interest (Subtopic 835-30), the Company continues to present deferred issuance costs related to its revolving credit facilities and related instruments as other assets.

The FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This newly issued accounting standard raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. Effective January 1, 2015, the Company adopted this ASU prospectively and as a result, its adoption had no impact on discontinued operations reported in prior periods.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted

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 2015-16 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 amendments in this ASU should be applied prospectively to adjustments to provisional amounts that occur after December 15, 2015 with earlier application permitted for financial statements that have not been issued. As the measurement period has closed for the Company's past acquisitions, the consolidated financial statements are not expected to be impacted, in that respect, by the adoption of this standard.

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

The FASB issued ASU 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. This ASU can be adopted either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The standard is effective for fiscal years and interim periods beginning after December 15, 2015. Early adoption is permitted. The prospective 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 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. This ASU may be applied using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. 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 2015-01, 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. This ASU may be applied prospectively or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted, but only as of the beginning of the fiscal year of adoption. The adoption of this standard is not expected to have an impact on the Company's results of operations.

2. Recently issued accounting pronouncements (continued)

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

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 effects of initially adopting ASU 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in a form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. ASU 2014-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. 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 2014-15, Presentation of Financial Statements - Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity's management should evaluate whether there are conditions or events that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. This ASU will be effective for the annual reporting period ending after December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued 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. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2015. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB and the International Accounting Standards Board have jointly issued a new revenue recognition standard codified in U.S. GAAP as ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. During the quarter, the FASB approved a one year deferral of the effective date of this new revenue standard and as such, it is now required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company is currently assessing the impact the adoption of this standard might have on its financial position or results of operations.

3. Business acquisitions and development projects

(a) Acquisition of Empire

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

Empire shareholders will receive U.S.$34.00 per common share in cash, which represents an aggregate purchase price of approximately $3,400,000 (U.S.$2,400,000), which includes the assumption of approximately $1,300,000 (U.S.$900,000) of debt.

The closing of the acquisition, which is expected to occur in early 2017, is subject to customary closing conditions, including the approval of Empire's common shareholders, and the receipt of certain state and federal regulatory and government approvals.

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

On March 1, 2016, the Company issued $1,000,000 aggregate principal amount of 5.0% convertible unsecured subordinated debentures represented by instalment receipts (the "Debentures" or the "Debenture Offering") and received the first instalment of $333,000. On March 9, 2016, the underwriters exercised their option to purchase $150,000 additional Debentures and received the first instalment of $49,950. The Debentures are expected to convert to common shares of the Company upon the closing of the acquisition of Empire (note 25).

(b) Acquisition of Park Water System

Subsequent to year-end, on January 8, 2016, the Company completed the acquisition of Western Water Holdings, LLC which is the parent company of Park Water Company ("Park Water System"), a regulated water distribution utility. Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and western Montana. The total purchase price for the Park Water System is U.S.$341,750, including debt assumed of U.S. $91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed through the consolidated statements of operations.

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

Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the City of Missoula will ultimately take possession of Mountain Water Company. The City's right to take Mountain Water Company is currently on appeal before the Montana Supreme Court, which is set to hear the appeal on April 22, 2016. If the City of Missoula prevails on appeal and ultimately takes possession of Mountain Water Company, the compensation to be paid by the City of Missoula for such taking will be the value of the utility plus accrued interest and attorney's fees as determined by the Montana court.

(c) 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.

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

3. Business acquisitions and development projects (continued)

(d) Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group 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.

(e) Commercial operation of Bakersfield Solar I Facility

In 2014, the Company completed construction 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.$57,160 and is recorded as property, plant and equipment on the consolidated balance sheets. The cost of the original development project is subject to certain adjustments which are expected to be finalized in 2016. 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 (the "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.

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, 2015.

(f) Commercial operation of Saint-Damase Wind Facility

In 2014, the Company completed construction of a 24 MW wind powered generating facility located near St. Damase, Quebec ("Saint-Damase Wind Facility") which achieved commercial operation on December 2, 2014. The cost of these generating assets amounts to $64,155 and is recorded as property, plant and equipment on the consolidated balance sheets. The weighted average useful life of the Saint-Damase Wind Facility is 34 years.

(g) Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S.$4,499.

(h) Acquisition of non-controlling interest in U.S. wind farms

On March 31, 2014, the Company acquired the 40% interest in Wind Portfolio SponsorCo, LLC ("Wind Portfolio SponsorCo") for approximately U.S.$115,000. Wind Portfolio SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. As a result of the transaction, the Generation Group now owns 100% of Wind Portfolio SponsorCo's Class B partnership units resulting in the elimination of the non-controlling interest in respect of the Class B partnership units of Wind Portfolio SponsorCo as follows:

Elimination of non-controlling interest in Class B partnership units	$	205,796
Non-controlling interest portion of currency translation adjustment recorded to AOCI		(21,029)
Non-controlling interest portion of unrealized gain on cash flow hedges recorded to AOCI		(2,543)
Decrease in deferred income tax asset		(32,551)
Additional paid-in capital		(22,552)
Cash	$	127,121

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

3. Business acquisitions and development projects (continued)

(i) Commercial operation of Cornwall Solar Facility

In 2014, the Company completed the construction of a 10 MWac solar powered generating facility located near Cornwall, Ontario ("Cornwall Solar Facility") which achieved commercial operation on March 27, 2014. The cost of these generating assets of $40,090 is recorded as property, plant and equipment while $7,243 is recorded as intangible assets, for a total investment of $47,333. The weighted average useful life of the Cornwall Solar Facility is 33 years.

(j) Acquisition of New England Gas System

On December 20, 2013, the Company acquired certain regulated natural gas distribution utility assets (the "New England Gas System") located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is $67,010 (U.S.$62,745), including the purchase price adjustment of U.S.$3,108 finalized in 2014.

In 2014, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed. The key retrospective adjustments to the assets and liabilities were an increase to the regulatory asset for pension of U.S.$2,701, a decrease of property, plant and equipment of U.S.$1,190, an increase of the environmental obligation of U.S.$2,467 and an increase of the pension obligation of U.S.$772.

(k) 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 2016. 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 2015 (2014 - U.S.$1,133).

4. Accounts receivable

Accounts receivable as of December 31, 2015 include unbilled revenue of $49,002 (2014 - $52,880) from the Company's regulated utilities. Accounts receivable as of December 31, 2015 are presented net of allowance for doubtful accounts of $7,966 (2014 - $7,229).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

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	64,779	—	64,779
Distribution	103,669	—	103,669
	$ 4,535,068	$ 661,384	$ 3,873,684

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

5. Property, plant and equipment (continued)

2014

	Cost	Accumulated depreciation	Net book value
Generation	$ 1,827,247	$ 270,746	$ 1,556,501
Distribution	1,555,289	147,726	1,407,563
Land	19,347	—	19,347
Equipment and other	119,367	29,526	89,841
Construction in progress			
Generation	82,840	—	82,840
Distribution	122,330	—	122,330
	$ 3,726,420	$ 447,998	$ 3,278,422

Generation assets include cost of $158,514 (2014 - $155,629) and accumulated depreciation of $38,507 (2014 - $34,013) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,117 (2014 - $2,274).

Investments tax credits, government grants and contributions received in aid of construction of $9,623 (2014 - $362) 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:

2015

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 78,725	$ 40,244	$ 38,481
Customer relationships	37,083	10,371	26,712
Interconnection agreements	13,000	230	12,770
	$ 128,808	$ 50,845	$ 77,963

2014

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 64,605	$ 33,704	$ 30,901
Customer relationships	31,094	7,984	23,110
Interconnection agreements	—	—	—
	$ 95,699	$ 41,688	$ 54,011

Estimated amortization expense for intangible assets for the next year is $5,420, $3,620 in year two, $3,250 in year three, $3,200 in year four and $3,160 in year five.

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

6. Intangible assets and goodwill (continued)

Changes in goodwill are as follows:

		Distribution Group
Balance, January 1, 2014	$	84,647
Foreign exchange		7,681
Balance, December 31, 2014	$	92,328
Business acquisitions		290
Foreign exchange		17,875
Balance, December 31, 2015	$	110,493

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

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

On June 26, 2015, the EnergyNorth Gas System received a Final Order from the New Hampshire Public Utility Commission approving a settlement agreement allowing for a U.S.$12,400 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 a 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 a rate increase of U.S.$4,625 effective February 20, 2015.

On March 17, 2014, the Granite State Electric System received a Final Order from the New Hampshire Public Utilities Commission approving a rate increase of U.S.$10,875 consisting of U.S.$9,760 in base rates and an additional U.S. $1,115 for incremental capital expended after the test year. In addition, the Order allows for a one time recovery of rate case expenses of U.S.$390. The new rates were effective as of April 1, 2014 for services rendered on and after July 1, 2013.

On April 18, 2014, the LPSCo Water System received a Final Order from the Arizona Corporation Commission approving a rate increase of U.S.$1,767 in connection with its rate application filed on February 28, 2013. The new rates became effective on May 1, 2014.

In May 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S.$3,235 in connection with its annual GRAM filing on October 1, 2013. The new rates were effective as of June 1, 2014 for services rendered on and after February 1, 2014.

On December 3, 2014, the Midstates Gas System received a Final Order from the Missouri Public Service Commission approving a rate increase of U.S.$4,868 effective January 2, 2015.

On December 4, 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S.$3,680 in connection with its annual GRAM filing on October 1, 2014. The new rates are effective as of February 1, 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:

		2015		2014
Regulatory assets				
Environmental remediation (a)	**$**	**116,747**	$	102,735
Pension and post-employment benefits (b)		**69,537**		63,512
Commodity costs adjustment (c)		**7,643**		41,502
Rate case costs (d)		**6,535**		4,161
Rate adjustment mechanism (e)		**14,804**		6,207
Other		**30,049**		29,155
Total regulatory assets	**$**	**245,315**	$	247,272
Less current regulatory assets		**(32,213)**		(61,645)
Non-current regulatory assets	**$**	**213,102**	$	185,627
Regulatory liabilities				
Cost of removal (f)	**$**	**107,988**	$	78,013
Rate-base offset (g)		**24,984**		23,427
Commodity costs adjustment (c)		**32,423**		10,389
Other		**9,952**		9,927
Total regulatory liabilities	**$**	**175,347**	$	121,756
Less current regulatory liabilities		**(44,167)**		(20,590)
Non-current regulatory liabilities	**$**	**131,180**	$	101,166

(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 $32,313 relates to a recent 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 services 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.

(c) Commodity costs adjustment

The revenue of the electric and natural gas utilities includes a component which is designed to recover the cost of electricity or natural gas through rates charged to customers. Under deferred energy accounting, to the extent actual natural gas and purchased power costs differ from natural gas and purchased power 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. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity 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 24(b)(i)) are recoverable through the commodity costs adjustment.

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

7. Regulatory matters (continued)

(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, 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 collected over a period not exceeding 24 months is accrued upon approval of the Final Order.

(f) 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.

(g) Rate-base offset

The regulators imposed a rate-base offset that would reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of ten 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 earns carrying charges on the regulatory balances related to commodity cost adjustment and rate case costs.

8. Long-term investments

Long-term investments consist of the following:

	2015	2014
Equity-method investees		
50% interest in Odell Wind Project Joint Venture (a)	**$ 42,287**	$ 2,267
50% interest in Deerfield Wind Project Joint Venture (b)	**2,240**	—
Interests in natural gas pipeline developments (c)	**5,623**	1,063
Other	**2,323**	3,268
	$ 52,473	$ 6,598
Available-for-sale investment	**$ 2,946**	$ 137
Notes receivable		
Development loans (d)	**$ 96,924**	$ 17,582
Red Lily Senior loan Tranche 2, interest at 6.31% (e)	**11,588**	11,588
Red Lily Subordinated loan Tranche 1, interest at 12.5% (e)	**6,565**	6,565
Other	**4,306**	3,775
	119,383	39,510
Total long-term investments	**174,802**	46,245
Less current portion	**—**	(2,966)
Total long-term investments	**$ 174,802**	$ 43,279

8. Long-term investments (continued)

(a) Odell Wind Project Joint Venture

On November 14, 2014, the Company acquired a 50% equity interest in Odell SponsorCo LLC ("Odell SponsorCo"), which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Project") in the state of Minnesota. The total construction costs of the Odell Wind Project are estimated to be U.S.$322,766.

The two members each contributed U.S.$1,000 to the capital of Odell SponsorCo on acquisition and another U.S.$23,800 on October 6, 2015. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments, within 30 days of commencement of operations, which is expected in 2016. The interest capitalized during the year to the investment while the Odell Wind Project is under construction amounts to $4,415 (2014 - nil).

As of December 31, 2015, Odell 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 Odell SponsorCo as the two members have joint control and all decisions must be unanimous. As such, the Company is accounting for the joint venture as an equity method investment. The Company's maximum exposure to loss is $190,840 as of December 31, 2015.

(b) Deerfield Wind Project Joint Venture

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. The total construction costs of the Deerfield Wind Project are estimated to be U.S.$303,000.

Upon the acquisition of the Deerfield Wind Project by Deerfield SponsorCo, the two members each contributed U.S.$1,000 to the capital of Deerfield SponsorCo. Upon execution of third-party construction loan and tax equity documents expected in 2016, each party will contribute another U.S.$18,596 plus accrued interest at 7% to the capital of Deerfield SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments at any time prior to the date that is 90 days following commencement of operations, which is expected in late 2016. The interest capitalized during the year to the investment while the Deerfield Wind Project is under construction amounts to $94.

As of December 31, 2015, 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 such, the Company is accounting for the joint venture as an equity method investment. The Company's maximum exposure to loss is $321,472 as of December 31, 2015.

(c) Natural gas pipeline developments

In December 2015, APUC acquired a 4.0% interest in Northeast Supply Pipeline LLC with an option to increase its participation to 10%. Northeast Supply LLC is a new entity undertaking the development, construction and ownership of natural gas transmission pipeline to be constructed between the Bradford and Susquehanna counties in Pennsylvania and Wright, NY. The project is expected to reach commercial operations by late 2018. The Company assessed that its interest of 4.0% in a limited liability corporation together with the option to increase its participation to 10% provide significant influence. As such, the interest is accounted as an equity method investment.

8. Long-term investments (continued)

(c) Natural gas pipeline developments (continued)

In November 2014, APUC acquired a 2.5% interest in Northeast Expansion LLC with an option to increase its participation to 10%. Northeast Expansion LLC is a new entity undertaking the development, construction and ownership of a natural gas transmission pipeline to be constructed between Wright, NY and Dracut, MA. The project is expected to reach commercial operations by late 2018. The Company assessed that its interest of 2.5% in a limited liability corporation together with the option to increase its participation to 10% and the commitment from its New Hampshire subsidiary to a firm gas transportation agreement for service on the pipeline facilities provide significant influence. As such, the interest is accounted as an equity method investment.

The total capital investment assuming the Company exercises its right to subscribe for 10% of each pipeline is estimated to be U.S.$520,000. As of December 31, 2015, APUC had invested U.S.$4,063 (2014 - U.S.$375) in the pipeline projects.

(d) Development loans

The Company entered into a committed loan and credit support facility with Odell SponsorCo and Deerfield SponsorCo (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 loan bears interest at an annual rate of 7%-8% on outstanding principal amount until commercial operation date and 5% thereafter until maturity date, and 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.

As of December 31, 2015, the Company had outstanding loans of U.S.$62,751 from Odell SponsorCo and U.S.$7,281 from Deerfield SponsorCo for development costs of the Joint Ventures' Wind Projects. No interest revenue is accrued on the loans due to insufficient collateral in the Joint Ventures.

As of December 31, 2015, the following credit support was issued by the Company: a U.S.$15,000 letter of credit on behalf of the Odell Wind Project, to the utility under the PPA; a U.S.$1,119 letter of credit on behalf of the the Odell Wind Project pursuant to the generator interconnection agreement; guarantee of the obligations of the Joint Ventures under the wind turbine supply agreements; guarantee of the obligations of the Deerfield Wind Project under the power purchase agreement and decommissioning plan; and, a U.S. $43,238 letter of credit and guarantee of the obligations of Deerfield SponsorCo, to the vendor under the membership interest purchase and contribution agreement. The initial value of the guarantee obligations is recognized under other long-term liabilities and was valued at U.S.$1,147 using a probability weighted discounted cash flow (level 3).

(e) Red Lily I

The Red Lily I Partnership (the "Partnership") is owned by an independent investor. APUC provides operation and supervision services to the Red Lily I project, a 26.4 MW wind energy facility located in southeastern Saskatchewan.

The Company's investment in Red Lily I is in the form of participation in a portion of the senior and subordinated debt facilities to the Partnership.

The senior debt facility consists of two tranches. A third-party lender advanced $27,000 of senior debt to the Partnership as Tranche 1. In 2011, APUC advanced $13,000 of senior debt as Tranche 2 to the Partnership and received a pre-payment of $1,412 in 2012. The third-party lender has also advanced $4,000 of senior debt Tranche 2 to the Partnership. The Company's senior loan Tranche 2 to the Partnership earned interest at the rate of 6.31% and was replaced by subordinated debt Tranche 2 on February 23, 2016 as described below. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, and the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

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

8. Long-term investments (continued)

(e) Red Lily I (continued)

Subsequent to year-end, on February 23, 2016, a second tranche of subordinated loan for an amount equal to $15,588 was advanced by the Company. The proceeds from this additional subordinated debt were used by Red Lily I to repay Tranche 2 of the Partnership's senior debt, including the Company's portion.

In connection with the subordinated debt facility, the Company has an 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, exercisable for a period of 90 days commencing on February 24, 2016.

The above notes are secured by the underlying assets of the respective facilities.

9. Long-term debt

Long-term debt consists of the following:

	2015	2014
Generation Group		
$350,000 revolving credit facility, interest rate is equal to bankers' acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is BA or LIBOR plus 1.45%, maturing July 31, 2019.	**$ 27,300**	$ 23,400
Algonquin Power Co.: Senior Unsecured Notes: $200,000 bearing an interest rate of 4.65%, maturing February 15, 2022; $150,000 bearing an interest rate of 4.82%, maturing February 15, 2021; $135,000 bearing an interest rate of 5.50%, maturing July 25, 2018. The notes have interest only payments, payable semi-annually in arrears.	**481,991**	481,438
Shady Oaks Wind Facility: Senior Debt: U.S.$76,000 Chinese Development Bank Corporation loan facility, bearing an interest rate of 6 month LIBOR plus 280 basis points. This facility was repaid in May 2015.	**—**	88,168
Long Sault Hydro Facility: Senior Debt: $34,760 bonds bearing an interest rate of 10.21%, maturing December 31, 2027. The bonds have interest and principal payments, payable monthly in arrears.	**34,760**	35,997
Chuteford Hydro Facility: Senior Debt: $2,587 bonds bearing an interest rate of 11.55%, maturing April 1, 2020. The bond has principal and interest payments, payable monthly in arrears.	**2,587**	3,022
Distribution Group		
U.S.$200,000 revolving credit facility, interest rate is equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.25%, maturing September 30, 2018.	**—**	23,898
Liberty Utilities Co.: Senior Unsecured Notes: U.S.$ 50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S.$ 25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S.$115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; U.S.$ 15,000, bearing an interest rate of 4.14%, maturing March 13, 2023; U.S.$ 75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; U.S.$ 60,000, bearing an interest rate of 4.89%, maturing July 30, 2027; U.S.$ 25,000, bearing an interest rate of 4.26%, maturing July 31, 2028; U.S.$ 90,000, bearing an interest rate of 4.13%, maturing April 30, 2045; U.S.$ 70,000, bearing an interest rate of 4.13%, maturing July 15, 2045. The notes have interest only payments, payable semi-annually.	**721,581**	419,876

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

	2015	2014
Calpeco Electric System: Senior Unsecured Notes: U.S.$45,000 bearing an interest rate of 5.19%, maturing December 29, 2020; U.S.$25,000 bearing an interest rate of 5.59%, maturing December 29, 2025. The notes have interest only payments, payable semi-annually in arrears.	**96,015**	80,368
Liberty Water Co: Senior Unsecured Notes: U.S.$50,000 bearing an interest rate of 5.60% $5,000 matures annually beginning June 20, 2016; $25,000 maturing December 22, 2020. The note bears interest payments semi-annually in arrears.	**68,488**	57,301
New England Gas System: First Mortgage Bonds: U.S.$6,500, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S.$7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S.$6,000, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.	**32,130**	27,288
Granite State Electric System: Senior Unsecured Notes: U.S.$5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S.$5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; U.S.$5,000, bearing an interest rate of 7.30%, maturing June 15, 2028. The notes have interest only payments, payable semi-annually.	**20,730**	17,373
LPSCo Water System: 1999 and 2001 IDA bonds bearing interest rates of 5.85% and 6.71%. This facility was repaid in October 2015.	**—**	12,441
Bella Vista Water System: U.S.$877 Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10%, and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears.	**1,213**	1,149
	$ 1,486,795	$ 1,271,719
Less: current portion	**(8,945)**	(9,130)
	$ 1,477,850	$ 1,262,589

9. Long-term debt (continued)

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to the Company. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Effective January 1, 2015, the Company applied ASU 2015-03 (note 2(a)) retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs of $8,304 as of December 31, 2014 that were previously presented as other assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term debt in the table above.

Generation Group

On October 30, 2015, the Generation Group entered into a new extendible one-year letter of credit facility agreement. The new facility expands the group's available liquidity by providing 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.

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

On December 31, 2014, the U.S.$19,200 senior debt for the Sanger thermal facility was repaid.

On July 31, 2014, the Company increased the credit available under the senior unsecured revolving credit facility to $350,000 from $200,000. The larger revolving credit facility will be used to provide additional liquidity in support of the Generation Group's development portfolio to be completed over the next three years. The maturity of the revolving credit facility has been extended to July 31, 2018. On May 27, 2015, the Generation Group extended the maturity of its senior unsecured revolving credit facility one year to July 31, 2019 with all other terms remaining the same.

On January 17, 2014, the Company issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year, commencing on February 15, 2014. The Company incurred deferred financing costs of $1,568, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, the Company entered into a cross currency swap, coterminous with the debentures, to economically 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 Company'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, an economic hedge of the net investment in a foreign operation is reported in the same manner as the translation adjustment (in OCI) related to the net investment (note 24(b)(iii)).

Distribution Group

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

On April 30, 2015, the Distribution Group 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 proceeds of the financing will be used in connection with the acquisition of the Park Water System and for general corporate purposes. 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.

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

9. Long-term debt (continued)

Corporate

APUC has a senior unsecured revolving credit of U.S.$65,000. subsequent to year end the maturity date of the facility was extended by one year to November 19, 2017. As of December 31, 2015 and 2014, no amounts were outstanding under this revolving credit facility.

Subsequent to year-end, on February 9, 2016, in connection with the acquisition of Empire (note 3 (a)), the Company obtained $2,200,000 (U.S.$1,600,000) in bridge financing commitments from a syndicate of banks. The non-revolving term credit facilities are comprised of a U.S.$1,065,000 debt bridge facility, repayable in full on the first anniversary following its advance, and a U.S.$535,000 equity bridge facility repayable in full on the first anniversary following its advance. On March 1, 2016, upon issuing the Debentures (including the overallotment) (note 25) and receiving the First Instalment, the Company reduced its bridge commitments by $359,950.

Subsequent to year-end, on January, 4, 2016, a subsidiary of APUC entered into a U.S.$235,000 term credit facility with two U.S. banks. The term credit facility is available for acquisitions and general corporate purposes and matures on July 5, 2017.

As of December 31, 2015, the Company had accrued $25,161 in interest expense (2014 - $18,770). Interest expense on the long-term debt in 2015 was $72,213 (2014 - $64,218).

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

	2016	2017	2018	2019	2020	Thereafter	Total
Generation Group	$ 1,816	$ 2,045	$ 137,272	$ 30,152	$ 2,641	$ 375,415	$ 549,341
Distribution Group	7,129	76,358	7,135	7,149	147,640	701,371	946,782
Total	$ 8,945	$ 78,403	$ 144,407	$ 37,301	$ 150,281	$ 1,076,786	$ 1,496,123

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 2015 were $4,132 (2014 - $3,287).

In conjunction with recent utilities 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.

(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

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	
	2015	**2014**	**2015**	**2014**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 241,963**	$ 178,113	**$ 68,257**	$ 45,399
Projected benefit obligation assumed from business combination	**—**	1,022	**—**	—
Modifications to pension plan	**(4,995)**	(560)	**—**	—
Service cost	**6,663**	4,828	**3,093**	2,022
Interest cost	**9,642**	8,549	**2,914**	2,186
Actuarial loss (gain)	**(16,098)**	39,704	**(8,466)**	14,893
Contributions from retirees	**—**	—	**412**	331
Benefits paid	**(13,024)**	(8,125)	**(2,447)**	(1,586)
Loss on foreign exchange	**45,231**	18,432	**12,802**	5,012
Projected benefit obligation, end of year	**$ 269,382**	$ 241,963	**$ 76,565**	$ 68,257
Change in plan assets				
Fair value of plan assets, beginning of year	**156,990**	139,280	**14,295**	13,395
Actual return (loss) on plan assets	**(5,657)**	6,568	**20**	1,176
Employer contributions	**7,975**	5,676	**3,028**	(222)
Benefits paid	**(12,589)**	(7,414)	**(2,036)**	(1,255)
Gain on foreign exchange	**29,453**	12,880	**2,842**	1,201
Fair value of plan assets, end of year	**$ 176,172**	$ 156,990	**$ 18,149**	$ 14,295
Unfunded status	**$ (93,210)**	$ (84,973)	**$ (58,416)**	$ (53,962)
Amounts recognized in the consolidated balance sheets consists of:				
Current liabilities	**(470)**	—	**(1,062)**	(333)
Non-current liabilities	**(92,740)**	(84,973)	**(57,354)**	(53,629)
Net amount recognized	**$ (93,210)**	$ (84,973)	**$ (58,416)**	$ (53,962)

The accumulated benefit obligation for the pension plans was $251,932 and $219,007 as of December 31, 2015 and 2014, respectively.

During 2015, the Company permanently froze the accrual of retirement benefits for union participants and most non-union participants under existing plans, effective December 31, 2015 and March 31, 2015, respectively. 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. $3,941 which is recorded as a prior service credit in OCI.

(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 amounts recognized in OCI before tax were as follows:

	AOCI	
	Pension	OPEB
Balance, January 1, 2014	$ (14,385)	$ (9,083)
Current year net actuarial gain	43,350	14,338
Current year prior service loss	(563)	—
Amortization of net actuarial loss	349	641
Balance at December 31, 2014	$ 28,751	$ 5,896
Current year net actuarial loss	1,505	(7,554)
Current year prior service credits	(4,864)	—
Amortization of net actuarial gain	(1,358)	(680)
Amortization of prior service credits	457	—
Balance at December 31, 2015	$ 24,491	$ (2,338)

The net actuarial loss for the defined benefit pension plans and OPEB that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $632 and $88, respectively.

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2015 and 2014 were as follows:

	Pension benefits		OPEB	
	2015	2014	2015	2014
Discount rate	**3.71%**	4.55%	**3.82%**	4.60%
Expected return on assets	**6.44%**	7.00%	**5.50%**	5.53%
Rate of compensation increase	**3.01%**	2.97%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.00%**	7.63%
Age 65 and after			**7.00%**	7.63%
Assumed Ultimate Medical Inflation Rate			**5.00%**	5.00%
Year in which Ultimate Rate is reached			**2019**	2019

Weighted average assumptions used to determine net benefit obligation for 2015 and 2014 were as follows:

	Pension benefits		OPEB	
	2015	2014	2015	2014
Discount rate	**4.16%**	3.71%	**4.23%**	3.80%
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)

The mortality assumption for December 31, 2015 was updated to the projected generationally scale MP-2015, adjusted to reflect the ultimate improvement rates in the 2015 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 2015 is as follows:

		2015
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	$	10,763
Total service and interest cost		1,111
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	$	(8,687)
Total service and interest cost		(871)

(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	
	2015	2014	**2015**	2014
Service cost	**$ 6,663**	$ 4,828	**$ 3,093**	$ 2,022
Interest cost	**9,642**	8,549	**2,914**	2,186
Expected return on plan assets	**(11,989)**	(10,018)	**(713)**	(628)
Amortization of net actuarial loss (gain)	**1,398**	(346)	**510**	(641)
Amortization of prior service credits	**(471)**	—	**—**	—
Net benefit cost	**$ 5,243**	$ 3,013	**$ 5,804**	$ 2,939

(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	74%	49% - 78%
Debt securities	26%	22% - 51%
Other	—%	0% - 1%

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

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

(d) Plan assets (continued)

The fair values of investments as of December 31, 2015, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	138,993	72%
Debt securities	54,542	28%
Other	787	—%

As of December 31, 2015, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $9,232 to its pension plans and $4,237 to its post-employment benefit plans in 2016.

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

	2016	2017	2018	2019	2020	2021-2025
Pension plan	$ 15,037	$ 13,829	$ 14,474	$ 15,120	$ 15,692	$ 88,692
OPEB	3,113	3,375	3,584	3,804	4,396	25,720

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.

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are:	
2016	$ 979
2017	908
2018	1,068
2019	1,282
2020	1,344
Thereafter to 2031	18,516
Redemption amount	5,340
	29,437
Less amounts representing interest	(10,910)
	18,527
Less current portion	(979)
	$ 17,548

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

12. Other assets

Other assets consist of the following:

	2015	2014
Restricted cash	**$ 18,999**	$ 18,702
Deferred financing costs	**3,211**	2,428
Other	**4,770**	4,475
	26,980	25,605
Less current portion	**(464)**	—
	$ 26,516	$ 25,605

13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	2015	2014
Advances in aid of construction (a)	**$ 92,285**	$ 81,104
Environmental remediation obligation (b)	**71,529**	70,072
Asset retirement obligations (c)	**17,799**	13,884
Customer deposits (d)	**15,074**	11,713
Deferred income (e)	**13,682**	13,132
Deferred credits (f)	**24,110**	19,130
Other	**25,277**	17,503
	259,756	226,538
Less current portion	**(36,621)**	(49,303)
	$ 223,135	$ 177,235

(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 20 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 2015, $4,637 (2014 - $4,608) 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 $78,495 (2014 - $72,594) which at discount rates ranging from 2.5% to 4.2% represents the recorded accrual of $71,529 as of December 31, 2015 (2014 - $70,072). Approximately $46,929 is expected to be incurred over the next three years with the balance of cash flows to be incurred over the following 29 years.

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

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

(b) Environmental remediation obligation (continued)

Changes in the environmental remediation obligation are as follows:

	2015	2014
Opening Balance	**$ 70,072**	$ 69,555
Remediation activities	**(10,621)**	(12,739)
Accretion	**2,147**	2,273
Changes in cash flow estimates	**3,171**	268
Revision in assumptions	**(5,843)**	1,954
Purchase price adjustment	**—**	2,726
Foreign exchange rate adjustment	**12,603**	6,035
Closing Balance	**$ 71,529**	$ 70,072

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, 2015, the Company has reflected a regulatory asset of $116,747 (2014 - $102,735) 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 of $506 (2014 - $2,570) for renewable generation facilities being constructed and accretion expense of $854 (2014 - $527).

(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.

(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 deferred tax credits (note 19) of $3,350 (2014 - $19,130).

14. Shareholders' capital

(a) Common shares

Number of common shares:

	2015	2014
Common shares, beginning of year	**238,149,468**	206,348,985
Public offering (i)	**14,355,000**	29,444,000
Issuance of shares under the dividend reinvestment (iv) and employee share purchase plans ((c)(ii))	**3,364,951**	2,356,483
Common shares, end of year	**255,869,419**	238,149,468

14. Shareholders' capital (continued)

(a) Common shares (continued)

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 April 2016. 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.

In December 2014, APUC issued 10,055,000 common shares at $9.95 per share pursuant to a public offering for proceeds of $100,047, before issuance costs of $4,243 or $3,021 net of taxes.

In September 2014, APUC issued 19,389,000 common shares at $8.90 per share pursuant to a public offering for proceeds of $172,562, before issuance costs of $7,648 or $5,719 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(a)). At any time, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by November 14, 2016, they will automatically convert into common shares.

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(b)). At any time, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by December 29, 2016, they will automatically convert into common shares.

(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 292,337 common shares under the dividend reinvestment plan.

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

14. 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, 2015 and 2014:

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, 2015, APUC recorded $5,330 (2014 - $3,248) in total share-based compensation expense detailed as follows:

	2015	2014
Share options	**$ 2,742**	$ 1,931
Directors deferred share units	**404**	273
Employee share purchase	**158**	116
Performance share units	**2,026**	928
Total share-based compensation	**$ 5,330**	$ 3,248

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, 2015, total unrecognized compensation costs related to non-vested options and PSUs were $3,125 and $1,866, respectively, and are expected to be recognized over a period of 1.74 and 1.63 years, respectively.

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

14. 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 10% 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.

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:

	2015	2014
Risk-free interest rate	**1.3%**	2.0%
Expected volatility	**38%**	38%
Expected dividend yield	**4.0%**	3.8%
Expected life	**8 years**	8 years
Weighted average grant date fair value per option	**$ 2.45**	$ 2.00

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, 2014	4,567,129	$ 5.70	5.45	$ 7,814
Granted	969,998	7.95	8.00	—
Balance at December 31, 2014	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
Exercisable at December 31, 2015	4,618,323	$ 5.74	3.55	$ 23,898

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(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, 2015, a total of 111,355 common shares (2014 - 93,598) 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, 2015, 157,471 (2014 - 110,241) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs.

(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.

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

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance share units (continued)

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, 2014	66,195	$ 6.57	0.62	$ 486
Granted	407,962	8.22	3.00	3,333
Exercised	(22,665)	6.13	—	(185)
Forfeited	(11,406)	8.22	—	(93)
Balance at December 31, 2014	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
Exercisable at December 31, 2015	157,972	$ 8.22	—	$ 1,723

15. 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, 2014	$ (57,471)	$ 11,840	$ —	$ 14,221	$ (31,410)
OCI (loss) before reclassifications	68,938	3,358	519	(35,396)	37,419
Amounts reclassified	—	5,423	(518)	(273)	4,632
Net current period OCI	68,938	8,781	1	(35,669)	42,051
Acquisition of non-controlling interest	21,029	2,543	—	—	23,572
Balance, December 31, 2014	$ 32,496	$ 23,164	$ 1	$ (21,448)	$ 34,213
OCI 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

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.

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

16. 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:

	2015		2014	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 124,831**	**$ 0.4867**	$ 83,097	$ 0.3695
Series A preferred shares	**$ 5,400**	**$ 1.1250**	$ 5,400	$ 1.1250
Series D preferred shares	**$ 5,000**	**$ 1.2500**	$ 4,103	$ 1.0257

17. Related party transactions

Emera Inc.

A member of the Board of APUC is an executive at Emera. During 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. $6,658 (2014 - U.S.$9,821). During 2015, Liberty Utilities purchased natural gas amounting to U.S. $2,292 (2014 - U.S.$3,961) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

There was U.S.$491 included in accruals in 2015 (2014 - U.S.$nil) related to these transactions at the end of the years.

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 $2,021 (2014 - $189) during the year.

Senior Executives

As at December 31, 2015, $nil (December 31, 2014 - $47) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively "Senior Executives").

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership.

The Company terminated the agreement effective June 28, 2015 and paid a usage shortfall fee of $13. During the year ended December 31, 2015, APUC reimbursed direct costs in connection with the use of the aircraft prior to termination of the block time agreement of $507 (2014 - $721).

Office Facilities

Until the fourth quarter of 2014, APUC had leased its head office facilities from an entity partially owned by Senior Executives. During the fourth quarter of 2014, APUC terminated the related party lease and moved all head office employees into new premises owned by the Company. Base lease costs for the year ended December 31, 2015 were $nil (2014 - $356).

Other

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Company. During the year ended December 31, 2015, APUC paid $22 (2014 - $192) in relation to these services. The spouse is no longer employed by the Company.

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 2016.

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

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

18. Non-controlling interests

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

	2015	2014
Net earnings attributable to Class B partnership units of Wind Portfolio SponsorCo (i)	**$ —**	$ 3,484
Net loss attributable to Class A partnership units (ii)	**(33,942)**	(27,199)
Other net earnings attributable to non-controlling interests	**1,966**	1,529
Total net loss attributable to non-controlling interests	**$ (31,976)**	$ (22,186)

(i) On March 31, 2014, the Company acquired the remaining Class B partnership units of Wind Portfolio SponsorCo from the non-controlling interest holder. As a result of the transaction, the Company now owns 100% of Wind Portfolio SponsorCo's Class B partnership units (note 3(h)).

(ii) The non-controlling Class A membership equity investors ("Class A partnership units") in the Senate, Minonk and Sandy Ridge wind facilities and, beginning December 31, 2014, the Bakersfield Solar facility 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).

19. 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% (2014 - 26.5%). The differences are as follows:

	2015	2014
Expected income tax expense at Canadian statutory rate	**$ 34,516**	$ 19,199
Increase (decrease) resulting from:		
Recognition of deferred credit	**(2,448)**	(5,763)
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	**(3,855)**	(1,677)
Non-taxable corporate dividend	**(3,311)**	(2,618)
Non-controlling interests share of income	**12,511**	8,824
Production tax credit	**(254)**	(339)
Allowance for equity funds used during construction	**(935)**	(746)
State taxes	**733**	604
Adjustment relating to prior periods	**2,431**	—
CRA Settlement	**2,709**	—
Other	**1,616**	(677)
Income tax expense	**$ 43,713**	$ 16,807

For the years ended December 31, 2015 and 2014, earnings from continuing operations before income taxes consist of the following:

	2015	2014
Canadian operations	**$ 28,481**	$ 11,930
U.S. operations	**101,768**	60,519
	$ 130,249	$ 72,449

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

19. Income taxes (continued)

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

	Current	Deferred	Total
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**
Year ended December 31, 2014			
Canada	$ 5,660	$ (3,538)	$ 2,122
United States	(1,986)	16,671	14,685
	$ 3,674	$ 13,133	$ 16,807

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, 2015 and 2014 are presented below:

	2015	2014
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 396,727**	$ 319,056
Pension and OPEB	**57,969**	54,458
Acquisition-related costs	**6,035**	5,168
Environmental obligation	**28,230**	28,555
Production tax credit	**3,027**	2,098
Reserves not currently deductible	**2,503**	2,315
Other	**4,970**	3,988
Total deferred income tax assets	**499,461**	415,638
Less valuation allowance	**(17,478)**	(15,534)
Total deferred tax assets	**481,983**	400,104
Deferred tax liabilities:		
Property, plant and equipment	**(544,616)**	(387,931)
Intangible assets	**(2,760)**	(2,752)
Outside basis in partnership	**(32,221)**	(15,194)
Regulatory accounts	**(28,270)**	(49,399)
Financial derivatives	**(31,806)**	(15,013)
Total deferred tax liabilities	**(639,673)**	(470,289)
Net deferred tax liabilities	**$ (157,690)**	$ (70,185)
Consolidated Balance Sheets Classification:		
Deferred tax assets	**$ 18,109**	$ 64,275
Deferred tax liabilities	**(175,799)**	$ (134,460)
Net deferred tax liabilities	**$ (157,690)**	$ (70,185)

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

19. Income taxes (continued)

The valuation allowance for deferred tax assets as at December 31, 2015 was $17,478 (2014 - $15,534). 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, 2015, 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
2016	$ —
2017 and onwards	967,499
	$ 967,499

On June 26, 2015, the Company entered into an agreement with the Canada Revenue Agency ("CRA") regarding a 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 $64,678 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.

20. 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 14 (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:

	2015	2014
Net earnings attributable to shareholders of APUC	**$ 117,480**	$ 75,701
Series A Preferred shares dividend	**5,400**	5,400
Series D Preferred shares dividend	**5,000**	4,103
Net earnings attributable to common shareholders of APUC	**$ 107,080**	$ 66,198
Discontinued operations	**(1,032)**	(2,127)
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	**$ 108,112**	$ 68,325
Weighted average number of shares		
Basic	**253,172,088**	213,953,870
Effect of dilutive securities	**3,344,632**	2,387,722
Diluted	**256,516,720**	216,341,592

The shares potentially issuable as a result of 1,627,525 share options (2014 - 1,786,401) are excluded from this calculation as they are anti-dilutive.

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

21. Segmented information

The Company's management's reporting structure is aligned under three business units: Generation, Transmission and Distribution. During the fourth quarter, Management determined that each business unit represents a reporting segment. The comparative information for 2014 has been reclassified to conform with the composition of the reporting segments presented in the current year.

Generation, owns or has interests in hydroelectric, solar, wind power facilities and co-generation. Distribution operates electric, natural gas and water distribution utilities. Finally, Transmission invests in rate regulated electric transmission and natural gas pipeline systems. The Transmission segment includes the equity method investment in the Natural Gas Pipeline Development (note 8(c)) which is not yet significant and as a result is not presented separately in the tables below but grouped within Corporate.

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

	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	213,750	1,210	278,561
Administrative expenses	10,822	21,570	8,283	40,675
Depreciation and amortization	67,293	82,513	—	149,806
Gain on foreign exchange	—	—	(2,631)	(2,631)
Operating income (loss) from continuing operations	75,045	116,388	(6,862)	184,571
Interest expense	29,395	34,971	1,627	65,993
Interest, dividend, equity and other income	(1,154)	(3,974)	(3,967)	(9,095)
Other expenses (gain)	(5,623)	391	2,656	(2,576)
Earnings (loss) before income taxes	$ 52,427	$ 85,000	$ (7,178)	$ 130,249
Property, plant and equipment	$1,895,617	$1,914,980	$ 63,087	$ 3,873,684
Equity-method investees	44,638	769	7,066	52,473
Total assets	2,345,905	2,532,894	112,926	4,991,725
Capital expenditures	55,992	141,445	6,758	204,195

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

21. Segmented information (continued)

	Year ended December 31, 2014			
	Generation	Distribution	Corporate	Total
Revenue	$ 218,765	$ 722,849	$ —	$ 941,614
Fuel and power purchased	39,264	381,622	—	420,886
Net revenue	179,501	341,227	—	520,728
Operating expenses	55,482	178,248	308	234,038
Administrative expenses	13,457	19,947	1,288	34,692
Depreciation and amortization	58,248	53,671	2,128	114,047
Gain on foreign exchange	—	—	(1,112)	(1,112)
	52,314	89,361	(2,612)	139,063
Interest expense	33,868	27,139	1,411	62,418
Interest, dividend and other income	(1,187)	(3,369)	(3,202)	(7,758)
Other expense (gain)	48	300	11,606	11,954
Earnings (loss) before income taxes	$ 19,585	$ 65,291	$ (12,427)	$ 72,449
Property, plant and equipment	$1,687,465	$1,531,166	$ 59,791	$3,278,422
Equity-method investees	3,520	500	2,578	6,598
Total assets	1,896,265	2,098,244	108,339	4,102,848
Capital expenditures	201,063	176,849	54,461	432,373

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 2015 or 2014: Hydro Québec 13% (2014 - 11%); Manitoba Hydro 13% (2014 - 13%); PJM 14% (2014 - 10%); and ComEd 11% (2014 - 10%). 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:

	2015	2014
Revenue		
Canada	**$ 86,977**	$ 92,267
United States	**940,878**	849,347
	$ 1,027,855	$ 941,614
Property, plant and equipment		
Canada	**$ 592,598**	$ 590,580
United States	**3,281,086**	2,687,842
	$ 3,873,684	$ 3,278,422
Intangible assets		
Canada	**$ 40,186**	$ 25,601
United States	**37,777**	28,410
	$ 77,963	$ 54,011

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