**UNITED STATES**

**SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

# FORM 40 F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

**OR**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2018** **Commission File Number** **001-37946**

# ALGONQUIN POWER & UTILITIES CORP.

**(Exact name of Registrant as specified in its charter)**

**N/A**
**(Translation of Registrant's name into English (if applicable))**

**Canada**
**(Province or other jurisdiction of incorporation or organization)**

**4911**
**(Primary Standard Industrial Classification Code Number (if applicable))**

**N/A**
**(I.R.S. Employer Identification Number (if applicable))**

**354 Davis Road**
**Oakville, Ontario**
**L6J 2X1, Canada**
**(905) 465-4500**

**(Address and telephone number of Registrant's principal executive offices)**

**CT Corporation System**
**111 Eighth Avenue**
**New York, New York 10011**
**(212) 894-8940**

**(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)**

Securities registered or to be registered pursuant to Section 12(b) of the Act:

| **Title of each class** | **Name of each exchange on which registered** |
|---|---|
| Common shares, no par value | The New York Stock Exchange |
| 6.875% Fixed-to-Floating Subordinated Notes – Series 2018-A due October 17, 2078 | The New York Stock Exchange |

Securities registered or to be registered pursuant to Section 12(g) of the Act:

Common Shares, no par value

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

☒ **Annual Information Form** ☒ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

As of December 31, 2018, there were 488,851,433 Common Shares outstanding.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

**Yes** ☒ **No** ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

This Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the registrant's Registration Statements on Form F-3 (File Nos. 333-220059 and 333-227246), F-10 (File No. 333-216616 and 333-227245) and Form S-8 (File Nos. 333-177418, 333-213648, 333-213650 and 333-218810) under the Securities Act of 1933, as amended.

## ANNUAL INFORMATION FORM

The Annual Information Form (the "AIF") of Algonquin Power & Utilities Corp. ("Algonquin" or "the Company") for the fiscal year ended December 31, 2018 is filed as Exhibit 99.1 to this annual report on Form 40-F. All capitalized terms used herein but not otherwise defined herein shall have the meanings given to such terms in the AIF.

## AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of Algonquin for the fiscal year ended December 31, 2018 are filed as Exhibit 99.2 to this annual report on Form 40-F.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis for the fiscal year ended December 31, 2018 is filed as Exhibit 99.3 to this annual report on Form 40-F.

## DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading "Disclosure Controls and Procedures" in the Management's Discussion and Analysis for the fiscal year ended December 31, 2018 (the "MD&A"), filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

## INTERNAL CONTROL OVER FINANCIAL REPORTING

**A. Management's report on internal control over financial reporting**

The Company's management, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Company's internal control over financial reporting framework 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 the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) 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 Company's consolidated financial statements.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

Management assessed the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2018, based on the framework established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment 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 assessment, management concluded that Algonquin's internal control over financial reporting was effective as of December 31, 2018 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of the Company.

**B. Auditor's attestation report on internal control over financial reporting**

Ernst & Young LLP, the independent registered public accounting firm of Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2018, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2018. The attestation report is provided in Exhibit 99.2 to this annual report on Form 40-F.

**C. Changes in internal control over financial reporting**

The information provided under the heading "Changes in Internal Controls Over Financial Reporting" in the Management's Discussion and Analysis for the fiscal year ended December 31, 2018, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

## AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin's board of directors has determined that it has two audit committee financial experts serving on its audit committee. Christopher Ball and Dilek Samil have been determined to be such audit committee financial experts and are independent, as that term is defined by the Toronto Stock Exchange's listing standards applicable to Algonquin and Rule 10A-3 of the Exchange Act. The SEC has indicated that the designation of Christopher Ball and Dilek Samil as audit committee financial experts does not make either of them an "expert" for any purpose, impose any duties, obligations or liability on Christopher Ball and Dilek Samil that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

## CODE OF ETHICS

Algonquin has adopted a code of business conduct and ethics (the "Code of Conduct") that applies to all employees and officers, including its Chief Executive Officer and Chief Financial Officer. The Code of Conduct is available without charge to any shareholder upon request to Ian Tharp, Telephone: (905) 465-4500, E-mail: ir@algonquinpower.com, Algonquin Power & Utilities Corp., 354 Davis Road, Oakville, Ontario L6J 2X1.

## PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading "Pre-Approval Policies and Procedures" in the Annual Information Form for the fiscal year ended December 31, 2018, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the years ended December 31, 2017 and 2018 were pre-approved by the audit committee.

## OFF-BALANCE SHEET ARRANGEMENTS

Algonquin is not a party to any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on its financial condition, results of operations or cash flows.

## TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading "Contractual Obligations" in the Management's Discussion and Analysis for the fiscal year ended December 31, 2018, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

## NON-GAAP FINANCIAL MEASURES

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this annual report on Form 40-F, including the MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under U.S. generally accepting accounting principles. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout the MD&A.

## CAUTION CONCERNING FORWARD LOOKING STATEMENTS

This document may contain statements that constitute “forward-looking information” within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but is not limited to: the future growth, results of operations, performance, business prospects and opportunities of the Corporation; expectations regarding earnings and cash flow; statements relating to renewable energy credits expected to be generated and sold; tax credits expected to be available and/or received; the expected timeline for regulatory approvals and permits; the expected approval timing and cost of various transactions; expectations and plans with respect to current and planned capital projects; expectations with respect to revenues pursuant to energy production hedges; expected completion dates for projects under development and construction; the resolution of legal and regulatory proceedings; expected demand for renewable sources of power; government procurement opportunities; expected capacity of and energy sales from new energy projects; business plans for APUC’s subsidiaries and joint ventures; expected future base rates; and the timing for closing of pending acquisitions, including the acquisition of Enbridge Gas New Brunswick Limited Partnership and the acquisition of St. Lawrence Gas Company, Inc. All forward-looking information is given pursuant to the “safe harbour” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation’s acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation's facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify appropriate projects to maximize the value of production tax credit qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's interests; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "Enterprise Risk Factors" in our Annual Information Form for the fiscal year ended December 31, 2018, filed as Exhibit 99.1 to this annual report on Form 40-F.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by applicable law. All forward-looking information contained herein is qualified by these cautionary statements.

## IDENTIFICATION OF THE AUDIT COMMITTEE

Algonquin has a standing Audit Committee of its board of directors established in accordance with Section 3(a)(58)(A) of the Exchange Act. The information provided under the heading "Audit Committee" identifying Algonquin's Audit Committee and confirming the independence of the Audit Committee in the Annual Information Form for the fiscal year ended December 31, 2018, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

## INTERACTIVE DATA FILE

The required disclosure for the fiscal year ended December 31, 2018 is filed as Exhibit 101 to this annual report on Form 40-F.

## MINE SAFETY DISCLOSURE

Not applicable.

## COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

Algonquin is subject to corporate governance requirements prescribed under applicable Canadian corporate governance practices, including the rules of the Toronto Stock Exchange ("Canadian Rules"). Algonquin is also subject to corporate governance requirements prescribed by the listing standards of the New York Stock Exchange ("NYSE") Stock Market, and certain rules and regulations promulgated by the SEC under the Exchange Act (including those applicable rules and regulations mandated by the Sarbanes-Oxley Act of 2002). In particular, Section 303A.00 of the NYSE Listed Company Manual requires Algonquin to have an audit committee that meets the requirements of Rule 10A-3 of the Exchange Act, and Section 303A.011 of the NYSE Listed Company Manual requires Algonquin to disclose any significant ways in which its corporate governance practices differ from those followed by U.S. companies listed on the NYSE. A description of those differences follows.

Section 303A.01 of the NYSE Listed Company Manual requires that boards have a majority of independent directors and Section 303A.02 defines independence standards for directors. Algonquin's Board of Directors is responsible for determining whether or not each director is independent. In making this determination, the Board of Directors has adopted the definition of "independence" as set forth in the Canadian National Instrument 58-101 *Disclosure of Corporate Governance Practices*. In applying this definition, the Board of Directors considers all relationships of its directors, including business, family and other relationships. Algonquin's Board of Directors also determines whether each member of its Audit Committee is independent pursuant to Canadian National Instrument 52-110 *Audit Committees* and Rule 10A-3 of the Exchange Act.

Section 303A.04(a) of the NYSE Listed Company Manual requires that all members of the nominating/corporate governance committee be independent. Algonquin's Corporate Governance Committee includes one director who is not independent, but the Committee has appointed a Nominating Sub-Committee consisting solely of independent directors that performs all responsibilities relating to the director nominations process.

Section 303A.05(a) of the NYSE Listed Company Manual requires that all members of the compensation committee be independent.

Section 303A.07(b)(iii)(A) of the NYSE Listed Company Manual requires, among other things, that the written charter of the audit committee state that the audit committee at least annually, obtain and review a report by the independent auditor describing the firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues. The written charter of the audit committee complies with Canadian Rules, but does not explicitly state that these functions are part of the purpose of the audit committee, which is not required by Canadian Rules.

Section 303A.08 of the NYSE Listed Company Manual requires that shareholders of a listed company be given the opportunity to vote on all equity compensation plans and material revisions thereto. Algonquin complies with Canadian Rules, which generally require that shareholders approve equity compensation plans. However, the Canadian Rules are not identical to the NYSE Rules. For example, Canadian Rules require shareholder approval of equity compensation plans only when such plans involve the issuance or potential issuance of newly issued securities. In addition, equity compensation plans that do not provide for a fixed maximum number of securities to be issued must have a rolling maximum number of securities to be issued, based on a fixed percentage of the issuer's outstanding securities and must also be approved by shareholders every three years. If a plan provides a procedure for its amendment, Canadian Rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or purchase price, or an extension of the term of an award benefiting an insider, the removal or exceeding of the insider participation limit prescribed by the Canadian Rules, an increase to the maximum number of securities issuable, or is an amendment to the amending provision itself.

Section 303A.09 of the NYSE Listed Company Manual requires that listed companies adopt and disclose corporate governance guidelines that address certain topics, including director compensation guidelines. Algonquin has adopted its Board Mandate, which is the equivalent of corporate governance guidelines, in compliance with the Canadian Rules. Algonquin's corporate governance guidelines do not address director compensation, but Algonquin provides disclosure about the decision making process for non-employee director compensation in the annual management information circular and Algonquin has adopted a policy on share ownership guidelines for non-employee directors.

Section 303A.10 of the NYSE Listed Company Manual requires that a listed company's code of business conduct and ethics mandate that any waiver of the code for executive officers or directors may be made only by the board or a board committee and must be promptly disclosed to shareholders. Algonquin's code of business conduct and ethics complies with Canadian Rules and does not include such a requirement.

Section 312 of the NYSE Listed Company Manual requires that a listed company obtain shareholder approval prior to the issuance of securities in connection with the establishment or amendment of certain equity compensation plans, issuances of securities to related parties, the issuance of 20% or greater of shares outstanding or voting power and issuances that will result in a change in control. Algonquin will follow the Canadian Rules for shareholder approval of new issuances of its common shares. Following the Canadian Rules, shareholder approval is required for certain issuances of shares that (i) materially affect control of Algonquin or (ii) provide consideration to insiders in aggregate of 10% or greater of the market capitalization of the listed issuer and have not been negotiated at arm's length. Shareholder approval is also required, pursuant to the Canadian Rules, in the case of private placements (x) for an aggregate number of listed securities issuable greater than 25% of the number of securities of the listed issuer which are outstanding, on a non-diluted basis, prior to the date of closing of the transaction if the price per security is less than the market price or (y) that during any six month period are to insiders for listed securities or options, rights or other entitlements to listed securities greater than 10% of the number of securities of the listed issuer which are outstanding, on a non-diluted basis, prior to the date of the closing of the first private placement to an insider during the six month period.

In addition to the foregoing, the Company may from time-to-time seek relief from the NYSE corporate governance requirements on specific transactions under the NYSE Listed Company Guide, in which case, the Company expects to make the disclosure of such transactions available on the Company's website at www.algonquinpower.com. Information contained on the Company's website is not part of this annual report on Form 40-F.

## UNDERTAKING

Algonquin undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

## CONSENT TO SERVICE OF PROCESS

Algonquin previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X. Any change to the name or address of the agent for service of Algonquin shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: February 28, 2019

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

## EXHIBIT INDEX

99.1 Annual Information Form of Algonquin for the year ended December 31, 2018.
99.2 Audited Annual Financial Statements of Algonquin for the year ended December 31, 2018.
99.3 Management's Discussion & Analysis of Algonquin for the year ended December 31, 2018.
99.4 Consent Letter from Ernst & Young LLP.
99.5 Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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99.7 Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.8 Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101 Interactive Data File.

**Exhibit 99.1**




ALGONQUIN POWER & UTILITIES CORP.

# ANNUAL INFORMATION FORM

For the year ended December 31, 2018

February 28, 2019

*All information contained in this AIF is presented as at December 31, 2018, unless otherwise specified. In this AIF, all dollar figures are in U.S. dollars, unless otherwise indicated.*

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## Caution Concerning Forward-looking Statements and Forward-looking Information

This document may contain statements that constitute “forward-looking information” within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but is not limited to: the future growth, results of operations, performance, business prospects and opportunities of the Corporation; expectations regarding earnings and cash flow; statements relating to renewable energy credits expected to be generated and sold; tax credits expected to be available and/or received; the expected timeline for regulatory approvals and permits; the expected approval timing and cost of various transactions; expectations and plans with respect to current and planned capital projects; expectations with respect to revenues pursuant to energy production hedges; expected completion dates for projects under development and construction; the resolution of legal and regulatory proceedings; expected demand for renewable sources of power; government procurement opportunities; expected capacity of and energy sales from new energy projects; business plans for APUC’s subsidiaries and joint ventures; expected future base rates; and the timing for closing of pending acquisitions, including the EGNB Acquisition and the acquisition of SLG. All forward-looking information is given pursuant to the “safe harbour” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation’s acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation’s facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify, acquire or develop appropriate projects to maximize the value of PTC qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation’s growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica or the Corporation’s joint venture with Abengoa acting in a manner contrary to the Corporation’s interests; a drop in the market value of Atlantica’s ordinary shares; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation’s interests; and fluctuations in the price and liquidity of the Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading “Enterprise Risk Factors”.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by applicable law. All forward-looking information contained herein is qualified by these cautionary statements.

## Non-GAAP Financial Measures

The terms "Net Utility Sales" and "Net Energy Sales" are used in this AIF. These terms are not recognized measures under U.S. GAAP. There is no standardized measure of "Net Utility Sales" or "Net Energy 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 "Net Utility Sales" and "Net Energy Sales" can be found in APUC's Management's Discussion and Analysis ("**MD&A**") for the year ended December 31, 2018 (which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar) under the headings "Liberty Utilities Group – 2018 Liberty Utilities Group Operating Results" and "Liberty Power Group – 2018 Liberty Power Group Operating Results". Such calculations and analysis are incorporated by reference herein.

Net Utility Sales

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

Net Energy Sales

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

# 1. CORPORATE STRUCTURE

## 1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. (" **APUC**") was originally incorporated under the *Canada Business Corporations Act* on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the Corporation amended its articles to change its name to Société Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the Corporation, among other things, created a new class of common shares, transferred its existing operations to a newly formed independent corporation, exchanged new common shares for all of the trust units of Algonquin Power Co. ("**APCo**") and changed its name to Algonquin Power & Utilities Corp. The head and registered office of APUC is located at Suite 100, 354 Davis Road, Oakville, Ontario L6J 2X1.

Unless the context indicates otherwise, references in this AIF to the " **Corporation**" refer collectively to APUC, its direct or indirect subsidiary entities and partnership interests held by APUC and its subsidiary entities.

## 1.2 Intercorporate Relationships

Most of the Corporation's business is conducted through subsidiary entities, including those entities which hold project assets. The table on the following page excludes certain subsidiaries. The assets and revenues of the excluded subsidiaries did not individually exceed 10%, or in the aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of the Corporation as at December 31, 2018. The voting securities of each subsidiary are held in the form of common shares, share quotas or partnership interests in the case of partnerships and their foreign equivalents, and units in the case of trusts.

The following table outlines the Corporation's significant subsidiaries:

| Significant Subsidiaries | Description | Jurisdiction | Ownership of Voting Securities |
|---|---|---|---|
| **LIBERTY POWER GROUP** | | | |
| AAGES (AY Holdings) B.V. ("**AY Holdings**") | Owner of equity interest in Atlantica | Netherlands | 100% |
| Algonquin Power Co. (or "**APCo**" dba Liberty Power) | | Ontario | 100% |
| St. Leon Wind Energy LP ("**St. Leon LP**") | Owner of the St. Leon Wind Facility | Manitoba | 100% |
| Minonk Wind, LLC | Owner of the Minonk Wind Facility | Delaware | 100%1 |
| Senate Wind, LLC | Owner of the Senate Wind Facility | Delaware | 100%1 |
| GSG6, LLC | Owner of the Shady Oaks Wind Facility | Illinois | 100% |
| Odell Wind Farm, LLC | Owner of the Odell Wind Facility | Minnesota | 100%1 |
| Deerfield Wind Energy, LLC | Owner of the Deerfield Wind Facility | Delaware | 100%1 |
| **LIBERTY UTILITIES GROUP** | | | |
| Liberty Utilities (Canada) Corp. ("**LU Canada**") | | Canada | 100% |
| Liberty Utilities Co. | | Delaware | 100% |
| Liberty Utilities (CalPeco Electric), LLC | Owner of the CalPeco Electric System | California | 100% |
| Liberty Utilities (Granite State Electric) Corp. | Owner of the Granite State Electric System | New Hampshire | 100% |
| Liberty Utilities (EnergyNorth Natural Gas) Corp. | Owner of the EnergyNorth Gas System | New Hampshire | 100% |

| Significant Subsidiaries | Description | Jurisdiction | Ownership of Voting Securities |
|---|---|---|---|
| Liberty Utilities (Midstates Natural Gas) Corp. | Owner of natural gas distribution utility assets in Missouri, Iowa and Illinois | Missouri | 100% |
| Liberty Utilities (Peach State Natural Gas) Corp. | Owner of the Peach State Gas System | Georgia | 100% |
| Liberty Utilities (New England Natural Gas Company) Corp. | Owner of the New England Gas System | Delaware | 100% |
| The Empire District Electric Company ("**Empire**") | Owner of, among other things, (i) electric and water distribution and electric transmission utility assets serving locations in Missouri, Kansas, Oklahoma and Arkansas, (ii) the Mid-West wind development project, and (iii) the Ozark Beach hydro facility in Missouri, the Riverton, Energy Center, and Stateline No. 1 natural gas-fired power generation facilities in Kansas and Missouri, the Asbury coal-fired power generation facility in Missouri and a 40% interest in the Stateline combined cycle gas facility in Missouri | Kansas | 100% |
| The Empire District Gas Company ("**EDG**") | Operator of a natural gas distribution utility in Missouri | Kansas | 100% |
| Liberty Utilities (Litchfield Park Water & Sewer) Corp. | Owner of the LPSCo System | Arizona | 100% |

1 The Corporation holds 100% of the managing interests, with 100% of the non-managing interests held by third party partners.

## 2. GENERAL DEVELOPMENT OF THE BUSINESS

The Corporation owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flow to support a growing dividend and share price appreciation.

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

| Liberty Utilities Group |
|---|
| Electric Utilities<br>Natural Gas Utilities<br>Water & Wastewater Utilities<br>Natural Gas and Electric Transmission |

| Liberty Power Group |
|---|
| Wind Power Generation<br>Solar Generation<br>Hydro Electric Generation<br>Thermal Co-Generation |

Information on selected operating facilities owned by these business units is described in Schedules A, B, C, D and E to this AIF.

The Corporation also owns an approximate 41.5% indirect beneficial interest in Atlantica Yield plc (" **Atlantica**"), a NASDAQ-listed company that acquires, owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission and water assets under long-term contracts. APUC reports its investment in Atlantica under the Liberty Power Group.

### Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 768,000 connections. The Liberty Utilities Group seeks to provide safe, high quality and reliable services to its customers and to deliver stable and predictable earnings to the Corporation. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group seeks to deliver continued growth in earnings through accretive acquisitions of additional utility systems.

### Liberty Power Group

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

### Corporate Development

The Corporation's development activities for projects either owned directly by the Corporation or indirectly through AAGES entities are undertaken primarily by Abengoa-Algonquin Global Energy Solutions ("**AAGES**"), a joint venture with Abengoa S.A. (" **Abengoa**"), an international infrastructure construction company. AAGES and its affiliates work with a global reach to identify, develop, and construct new renewable power generating facilities, power transmission lines and water infrastructure assets. Once a project developed by AAGES has reached commercial operation, the Corporation will work with AAGES to jointly determine whether it would be optimal for such project to be held by the Corporation, remain in AAGES, or be offered for sale to Atlantica or, in limited circumstances, another party.

## 2.1 Three Year History and Significant Acquisitions

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

### 2.1.1 Fiscal 2016

### Corporate

#### (i) Financing Related to the Empire Acquisition

In the first quarter of 2016, in connection with the acquisition of Empire (the " **Empire Acquisition**") discussed below, APUC and its direct wholly-owned subsidiary, LU Canada, entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, C$1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("**Debentures**") of APUC represented by instalment receipts and also obtained $1.6 billion in acquisition financing commitments from a syndicate of banks (the "**Empire Acquisition Facility**"). As at December 31, 2018, more than 99.9% of the Debentures had been converted into Common Shares. For more detail about the Empire business, see "Description of the Business – Liberty Utilities Group – Description of Operations – Electric Distribution Systems" below.

#### (ii) $235 Million Corporate Term Credit Facility

On January 4, 2016, the Corporation entered into a $235 million term credit facility with two U.S. banks. The proceeds of the term credit facility provided additional liquidity for general corporate purposes and acquisitions. In March 2017, the Corporation repaid $100 million of borrowings. In October 2017, the Corporation extended the maturity of the term credit facility to July 5, 2019.

### Liberty Power Group

#### (i) Completion of the Odell Wind Facility

On July 29, 2016, the 200 MW Odell Wind Facility achieved commercial operation. On August 5, 2016, the tax equity financing of approximately $180 million was completed and on September 15, 2016 the Liberty Power Group acquired control of the project. The Odell Wind Facility has a 20-year PPA with a large investment grade utility. For more detail, see "Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities" below.

**(ii) Purchase of Turbines to Safe Harbour Production Tax Credit Rate**

At the end of 2016, the Liberty Power Group purchased approximately C$75 million of turbine components that are expected to qualify for approximately 600 MW of new projects for 100% of the production tax credit ("**PTC**"). The full PTC currently is $24 per MWh and is subject to an annual adjustment for inflation. The full PTC is available for U.S. wind projects on which construction commenced in 2016 in accordance with Internal Revenue Service safe harbour rules, including through the purchase of components, and then is reduced in 20% annual increments to 40% until being eliminated for projects on which construction commences after 2019. To qualify for PTCs at the level specified for a particular year, the project must have commenced construction during that year (which may include the purchase of components), and must be placed in service within four years following the end of that year unless construction or, in some cases, certain other efforts to advance the project, can be shown to have been continuous in accordance with Internal Revenue Service guidance. A wind project will receive PTCs at 100% of the full rate if construction commenced in 2016 and the project is placed in service prior to the end of 2021, at 80% of the full rate if construction commenced in 2017 and the project is placed in service prior to the end of 2021, at 60% of the full rate if construction commenced in 2018 and the project is placed in service prior to the end of 2022, and at 40% of the full rate if construction commences in 2019 and the project is placed in service prior to the end of 2023. Securing access to the full PTC rate is an important competitive advantage in the U.S. market. The Liberty Power Group plans to use its safe harbour equipment for the construction of Phase I of the Broad Mountain Wind Project and for the Sugar Creek Wind Project, with additional projects to be determined as final construction schedules are complete.

### Liberty Utilities Group

**(i) Acquisition of the Liberty Park Water System**

On January 8, 2016, the Liberty Utilities Group closed its acquisition of a regulated water distribution utility holding company, Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("**Liberty Park Water**"). Total consideration for the utility purchase was $341.3 million, which included the assumption of approximately $91.8 million of existing debt. Liberty Park Water owns and operates two regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California (the "**Liberty Park Water System**") and, at the time of closing, owned one regulated water utility in western Montana, which was subsequently transferred to the City of Missoula for approximately $84 million in June 2017 following condemnation proceedings.

## 2.1.2 Fiscal 2017

### Corporate

**(i) Agreement for the Formation of AAGES and Purchase of Interest in Atlantica Yield plc**

On November 1, 2017, APUC announced that it had entered into a memorandum of understanding to create AAGES to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the agreement to create the AAGES joint venture, APUC announced that it had entered into a definitive agreement to purchase from Abengoa an indirect 25% equity interest in Atlantica (the "**Initial Atlantica Investment**") for a total purchase price of approximately $608 million, or $24.25 per ordinary share of Atlantica, plus a contingent payment of up to $0.60 per share payable two years after closing, subject to certain conditions.

**(ii) November 2017 Offering of Common Shares**

Coincident with the announcement of the Abengoa/Atlantica transaction on November 1, 2017, APUC announced a bought deal offering of Common Shares. The offering, including the exercise in full of the underwriters' over-allotment option, closed on November 10, 2017. A total of 43,470,000 Common Shares were sold at a price of C$13.25 per share for gross proceeds of approximately C$576 million.

**(iii) Corporate Credit Facilities**

During the third quarter of 2017, the Corporation's senior unsecured bilateral revolving facility was increased from C$65 million to C$165 million and the maturity was extended to November 19, 2018. In November 2018, the maturity date was extended to November 19, 2019. During the fourth quarter of 2017, the Corporation entered into a term credit agreement in the amount of $600 million with a maturity of December 21, 2018 to support the closing of its transactions with Abengoa and Atlantica, as described above. On March 7, 2018, the Corporation drew $600 million under this facility and during 2018, the Corporation repaid $413 million of borrowings. In December 2018, the maturity date was extended to June 21, 2019.

## Liberty Power Group

### (i) Issuance of C$300 million of Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued C$300 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of C$99.929 per C$100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

### (ii) Completion of Deerfield Wind Facility

On February 21, 2017, the 149 MW Deerfield Wind Facility achieved commercial operation, on March 14, 2017, the Liberty Power Group acquired the remaining 50% interest in the project, and on May 10, 2017, tax equity financing of approximately $167 million was completed. The project has a 20-year PPA with a local electric distribution utility.

### (iii) Credit Facilities

On April 19, 2017, the Liberty Power Group entered into a C$150 million senior unsecured bilateral revolving credit facility with a maturity date of August 19, 2018 ("**Liberty Power Bilateral Facility**"). On October 6, 2017, the Liberty Power Group amended its existing revolving credit facility, increasing the size to $500 million for an initial term of five years. Concurrently the Liberty Power Bilateral Facility was fully repaid and cancelled. On August 1, 2018 the maturity date of the Liberty Power Group $500 million revolving credit facility was extended by one year to October 6, 2023.

## Liberty Utilities Group

### (i) Completion of the Empire District Electric Acquisition

On January 1, 2017, the Liberty Utilities Group successfully completed its acquisition of Empire for an aggregate purchase price of approximately $2.4 billion including the assumption of approximately $0.9 billion of debt. Empire is a Joplin, Missouri based regulated electric, gas and water utility serving customers in Missouri, Kansas, Oklahoma, and Arkansas.

For more detail about the Empire business, see "Description of the Business – Liberty Utilities Group – Description of Operations – Electric Distribution Systems" below.

### (ii) Completion of Financing Related to the Empire Acquisition

On March 1, 2017, Liberty Utilities Group's financing entity entered into an agreement to issue $750 million of senior unsecured notes by way of private placement. The notes are of varying maturities ranging from three to 30 years with a weighted average life of approximately 15 years and an effective weighted average interest expense of 3.6% (inclusive of interest rate hedges). The closing of the offering occurred on March 24, 2017, with the proceeds used to repay the balance of the Empire Acquisition Facility and other existing indebtedness.

### (iii) Completion of the Luning Solar Facility

On February 15, 2017, the Liberty Utilities Group obtained control of a 50 MW solar generating facility located in Mineral County, Nevada (the "**Luning Solar Facility**") for approximately $110.9 million. The net capital cost of the project is included in the rate base of the CalPeco Electric System as energy produced from the project is being consumed by the utility's customers.

### (iv) Definitive Agreement to Acquire St. Lawrence Gas Company, Inc.

On August 31, 2017, the Liberty Utilities Group announced the entering into of a definitive agreement with Enbridge Gas Distribution Inc., a subsidiary of Enbridge Inc., to acquire St. Lawrence Gas Company, Inc. ("**SLG**"), a regulated natural gas distribution utility located in northern New York State, and its subsidiaries. The proposed transaction is structured as a stock purchase in exchange for a cash purchase price of $70 million less the total amount of outstanding SLG indebtedness (which will be assumed by the Liberty Utilities Group at closing and is currently expected to be approximately $10 million) and is subject to customary working capital adjustments. Closing of the acquisition remains subject to regulatory approval and other customary closing conditions and is expected to occur in mid-2019.

### 2.1.3 Fiscal 2018

#### Corporate

**(i) Acquisition of Aggregate 41.5% Interest in Atlantica**

On March 9, 2018, the Corporation completed the formation of AAGES and the Initial Atlantica Investment closed. APUC filed a business acquisition report dated April 16, 2018 in respect of the Initial Atlantica Investment which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

On November 27, 2018, the Corporation, through its indirect subsidiary AY Holdings, completed the purchase of an additional stake of 16,530,348 ordinary shares of Atlantica from Abengoa (the "**Additional Atlantica Investment**"), for a total purchase price of $20.90 per share, comprised of a payment on closing of approximately $305 million, with up to $40 million payable at a later date contingent on satisfaction of certain conditions. The purchase of the additional stake brings the Corporation's total interest in Atlantica to approximately 41.5% of the ordinary shares outstanding. APUC filed a business acquisition report dated January 22, 2019 in respect of the Additional Atlantica Investment which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

The funds for the $305 million paid on closing of the Additional Atlantica Investment were drawn on the APUC's credit agreement dated November 19, 2012, as amended from time to time (the "**Corporation Credit Facility**"). On November 28, 2018, AAGES obtained a secured credit facility in the amount of $306.5 million (the "**AAGES Secured Credit Facility**") and subscribed to a preference share ownership interest in AY Holdings, which subscription proceeds were distributed by AY Holdings to APUC and used by APUC to repay the $305 million drawn under the Corporation Credit Facility. The AAGES Secured Credit Facility is collateralized through a pledge of all of the Atlantica ordinary shares held by AY Holdings.

**(ii) April 2018 Offering of Common Shares**

Coincident with the initial announcement of the Additional Atlantica Investment on April 17, 2018, APUC announced an offering of 37,505,274 Common Shares at a price of C$11.85 per share for gross proceeds of approximately C$444.4 million. The Common Shares were offered and sold directly to certain institutional investors. The offering closed on April 24, 2018.

**(iii) Offering of Subordinated Notes**

On October 17, 2018, APUC completed an underwritten offering of 6.875% fixed-to-floating subordinated notes – Series 2018-A (the "**Subordinated Notes**"). Under the offering, APUC issued $287.5 million aggregate principal amount of Subordinated Notes, including the exercise in full of the underwriters' over-allotment option. The Subordinated Notes are redeemable by APUC on or after October 17, 2023 and have a maturity date of October 17, 2078. Upon the occurrence of certain bankruptcy-related events in respect of APUC, the Subordinated Notes automatically convert into preferred shares, Series F of APUC (the "**Series F Shares**"). See "Description of Capital Structure – Subordinated Notes" for more detail on the Subordinated Notes and see "Description of Capital Structure – Preferred Shares" for more detail on the Series F Shares.

**(iv) AAGES Definitive Agreement to Acquire ATN3 Electric Transmission Project**

On November 8, 2018, AAGES entered into a definitive agreement with Abengoa Perú S.A. and Abengoa Greenfield Perú S.A. to acquire ATN 3, S.A. ("**ATN3**"), a Peruvian entity that owns an electric transmission project in southeast Peru in late-stage development, consisting of a new 220 kV power transmission line approximately 320 km in length, a new 138 kV power transmission line approximately 7.2 km in length, two new substations and the expansion of three existing substations (the "**ATN3 Project**"). Closing of the transaction remains subject to various conditions, including receipt of certain approvals from the government of Peru.

**(v) December 2018 Offering of Common Shares**

On December 20, 2018, APUC completed an offering of 12,536,350 Common Shares at a price of C$13.76 per share for gross proceeds of approximately C$172.5 million. The Common Shares were offered and sold directly to certain institutional investors.

## Liberty Power Group

### (i) Acquisition of Walker Ridge Wind Project

On February 9, 2018, the Liberty Power Group completed the acquisition of a 100% interest in the Walker Ridge project, an approximately 144 MW wind power electric generating development project located in Lake and Colusa Counties, California (the "**Walker Ridge Wind Project**").

### (ii) Increase to Letter of Credit Facility

On February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to $200 million and extended the maturity date to January 31, 2021. The facility continues to be a one-year extendible facility.

### (iii) Completion of Great Bay Solar Facility and Amherst Island Wind Facility

On March 29, 2018, the 75 MW Great Bay Solar Facility achieved commercial operation. On June 15, 2018, the 75 MW Amherst Island Wind Facility achieved commercial operation.

### (iv) Acquisition of Broad Mountain Wind Project

On June 11, 2018, the Liberty Power Group completed the acquisition of a 100% interest in the Broad Mountain project, an approximately 200 MW wind power electric generating development project located in Carbon County, Pennsylvania (the "**Broad Mountain Wind Project**").

### (v) Acquisition of Sugar Creek Wind Project

On December 4, 2018, the Liberty Power Group completed the acquisition of a 100% interest in the Sugar Creek wind project, an approximately 202 MW wind power electric generating development project located in Logan County, Illinois (the "**Sugar Creek Wind Project**"). The Liberty Power Group has entered into a 10-year energy production hedge, and three separate REC agreements, with respect to energy produced at the Sugar Creek Wind Project.

## Liberty Utilities Group

### (i) Liberty Utilities Credit Facilities

On February 23, 2018, the Liberty Utilities Group increased availability under its senior unsecured syndicated revolving credit facility from $200 million to $500 million and extended the maturity of such facility to 2023. The Liberty Utilities Group simultaneously canceled a $200 million revolving credit facility previously available to Empire.

### (ii) Definitive Agreement to Acquire Enbridge Gas New Brunswick Limited Partnership

On December 4, 2018, the Liberty Utilities Group entered into an agreement to purchase Enbridge Gas New Brunswick Limited Partnership ("**EGNB**"), a subsidiary of Enbridge Inc., along with its general partner, for C$331 million, subject to certain customary adjustments (the " **EGNB Acquisition**"). EGNB is a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick and operates approximately 800 kilometres of natural gas distribution pipeline. Closing of the EGNB Acquisition is expected to occur in 2019 and remains subject to customary closing conditions, including the receipt of regulatory and government approvals.

### (iii) Progress Made on Customer Savings Plan

In 2017, Empire proposed to its regulators in Missouri, Kansas, Oklahoma and Arkansas a customer savings plan which would phase out its Asbury coal generation facility and develop additional wind generation in or near its service territory that will utilize all available PTCs. The plan calls for the development of up to 600 MW of sustainable, cost-effective wind power to serve the needs of electricity customers within the Liberty Utilities Group's Midwest electric service territory and forecasts cost savings for customers of approximately $169 million and $325 million over a 20-year and 30-year period, respectively.

On July 11, 2018, Empire received an order from the MPSC supporting various requests related to its proposed plan, which has allowed the Liberty Utilities Group to continue to pursue the development of up to 600 MW of wind power and recognizes that "millions of dollars of customer savings could be of considerable benefit to Empire's customers and the entire state".

On October 18, 2018 and November 18, 2018, Empire filed with the MPSC a request for Certificates of Convenience and Necessity, in each case for 300 MW of the 600 MW contemplated as part of the initiative. A final hearing on the merits is scheduled for April 2019.

### 2.1.4 Recent Developments – 2019

#### Liberty Power Group

**(i) Issuance of C$300 million of Senior Unsecured Debentures**

On January 29, 2019, the APCo issued C$300 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures were sold at a price of C$999.52 per C$1,000.00 principal amount. This was the Liberty Power Group's inaugural "green bond" offering, with the debentures being issued under the APCo Green Bond Framework, which was adopted in January 2019. Pursuant to the requirements of the APCo Green Bond Framework, the net proceeds of any "green bond" offering are to be used to finance and/or refinance investments in renewable power generation and clean energy technologies.

#### Liberty Utilities Group

**(i) Acquisition of Ownership Interest in Wataynikaneyap Power Transmission Project**

On January 17, 2019, the Liberty Utilities Group acquired from Fortis Inc. an ownership interest in the Wataynikaneyap Power project, an electricity transmission project located in Northwestern Ontario that is expected to connect 17 remote First Nation communities to the Ontario provincial electricity grid through the construction of approximately 1,800 km of transmission lines (the "**Wataynikaneyap Power Transmission Project**"). Ownership of the Wataynikaneyap Power Transmission Project is divided as follows: 9.8% held by the Liberty Utilities Group, 39.2% held by Fortis Inc. and 51% held equally among 24 First Nation partners. The initial phase of the Wataynikaneyap Power Transmission Project connecting Pikangikum First Nation to Ontario's power grid was completed in late 2018. The next two phases are subject to receipt of all necessary regulatory approvals, including leave-to-construct approval from the Ontario Energy Board, which is expected in the first half of 2019. In addition to providing participating First Nations communities ownership in the transmission line, the Wataynikaneyap Power Transmission Project is expected to result in socio-economic benefits for surrounding communities, reduce environmental risk and lessen greenhouse gas emissions associated with diesel-fired generation currently used in the area.

# 3. DESCRIPTION OF THE BUSINESS

## 3.1 Liberty Power Group

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

The Liberty Power Group owns and operates hydroelectric, wind, solar and thermal facilities with a combined gross generating capacity of approximately 1.5 GW. Approximately 86% of the electrical output is sold pursuant to long-term contractual arrangements which as of December 31, 2018 had a production-weighted average remaining contract life of approximately 14 years. Details with respect to certain Liberty Power Group facilities and the term of related PPAs and energy production hedges (as applicable) are set out in Schedules A and B to this AIF.

### 3.1.1 Description of Operations

#### Wind Power Generating Facilities

**(i) Production Method**

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high-speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

**(ii) Principal Markets and Distribution Methods**

The principal markets for the Liberty Power Group's material operational wind facilities in Canada are Manitoba (the St. Leon Wind Facility) and Ontario (the Amherst Island Wind Facility). The electricity generated by the wind turbines is transmitted to the transmission system of the purchaser, being Manitoba Hydro in the case of the St. Leon Wind Facility and the IESO in the case of the Amherst Island Wind Facility. The principal markets for Liberty Power Group's wind facilities in the United States are PJM, MISO and ERCOT.

**(iii) Selected Facilities**

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 103.9 MW wind powered electrical generating facility located near St. Leon, Manitoba, approximately 150 km southwest of Winnipeg. The St. Leon Wind Facility entered into a PPA with Manitoba Hydro effective June 17, 2006 under which all electricity produced is sold to Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional five years.

(2) Shady Oaks Wind Facility

The Shady Oaks Wind Facility is a 109.5 MW wind powered electrical generating facility located in Lee County, Illinois, approximately 80 km west of Chicago. The Shady Oaks Wind Facility is party to a 20-year power sales contract with the largest electric utility in the state of Illinois, Commonwealth Edison. 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. Annual production is subject to contingent curtailment based on certain regulatory constraints of the electricity purchaser. The remaining generation and associated RECs are sold into the market.

(3) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind powered electrical generating facility located in Centre County, Pennsylvania, 180 km east of Pittsburgh. Sandy Ridge Wind, LLC is party to a long-term energy production hedge (a "**Primary Energy Production Hedge**") with respect to the majority of production with J.P. Morgan Ventures Energy Corporation ("**JPMVEC**"), a wholly owned subsidiary of J.P. Morgan, having a term of 10 years beginning January 1, 2013 and is also party to energy production hedges with another third party for production from 2023 to 2028. Based on the JPMVEC contract quantity, approximately 72% of energy revenues are expected to be earned under the Primary Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the PJM market.

(4) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind powered electrical generating facility located near Minonk, IL, approximately 200 km southwest of Chicago, Illinois. The Liberty Power Group first acquired an indirect interest in the Minonk Wind Facility on December 10, 2012. Minonk Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013 and is also party to energy production hedges with another third party for production from 2023 to 2024. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under the Primary Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the PJM market.

(5) Senate Wind Facility

The Senate Wind Facility is a 150 MW wind powered electrical generating facility located near Graham, Texas, approximately 200 km west of Dallas, Texas. Senate Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 15 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under the Primary Energy Production Hedge. RECs are sold into the ERCOT market.

(6) Odell Wind Facility

The Odell Wind Facility is a 200 MW wind powered electrical generating facility located near Windom, Minnesota, approximately 230 km southwest of Minneapolis, Minnesota. Odell Wind Farm LLC has entered into a PPA with an investment grade utility under which all electricity and RECs produced at the facility are sold. The term of the PPA is 20 years.

(7) Deerfield Wind Facility

The Deerfield Wind Facility is a 149 MW wind powered electrical generating facility located in central Michigan, approximately 180 km north of Detroit, Michigan. All energy, capacity, and RECs produced at the facility are sold to a local electric distribution utility pursuant to a 20-year PPA.

(8) Amherst Island Wind Facility

The Amherst Island wind facility is a 75 MW wind powered electric generating facility located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario (the "**Amherst Island Wind Facility**"). The electricity generated by the project is being sold under a 20-year PPA awarded as part of the IESO FIT program. During 2018, the Liberty Power Group's interest in the project was held in a joint venture with the EPC contractor. The Liberty Power Group has since exercised its option to acquire, at a pre-agreed price, the balance of the joint venture interest not previously owned. The acquisition is subject to regulatory approval, which is expected to be obtained in 2019.

### Solar Power Generating Facilities

#### (i) Production Method

Solar power is the conversion of sunlight into electricity, either directly using photovoltaics or indirectly using concentrated solar power. The Corporation's solar generation facilities, the Cornwall Solar Facility, Bakersfield I Solar Facility, the Bakersfield II Solar Facility and the Great Bay Solar Facility utilize photovoltaics which convert light into electric current using the photovoltaic effect. The array of a photovoltaic power system produces direct current power which fluctuates with the sunlight's intensity. For practical use, commercial installations convert this direct current generated power to alternating current through the use of inverters.

#### (ii) Principal Markets and Distribution Methods

The principal markets for the Liberty Power Group's operational solar facilities are Ontario for the Cornwall Solar Facility, California for the Bakersfield I Solar Facility and the Bakersfield II Solar Facility, and PJM for the Great Bay Solar Facility. The electricity generated by the solar panels is transmitted via electrical collection lines to the facility substation for subsequent delivery to the distribution/transmission system under control of the local distribution company and the ISO.

#### (iii) Selected Facilities

(1) Bakersfield I Solar Facility

The Bakersfield I Solar Facility is a 20 MW ground mounted photovoltaic solar powered electric generating facility that uses single axis trackers to optimize the site's generating efficiency. The site is located near Bakersfield, California, 150 km northwest of Los Angeles, California. The Bakersfield I Solar Facility achieved commercial operation in April 2015 and has a fixed rate PPA with an investor-owned utility with a term of 20 years from commencement of commercial operation.

(2) Great Bay Solar Facility

The Great Bay Solar Facility is a 75 MW solar powered electric generating facility comprising four sites located in Somerset County in southern Maryland. All energy from the project is sold to the U.S. Government Services Administration pursuant to a 10-year PPA, with a 10 year extension option. All RECs from the project are retained by the project company and sold into the Maryland market.

### Hydroelectric Generating Facilities

#### (i) Production Method

A hydroelectric generating facility consists of a number of key components, including a dam, intake structure, electromechanical equipment consisting of a turbine(s) and a generator(s). A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace, as well as to provide sufficient depth within the reservoir for an intake. Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal and an intake structure. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy. The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

**(ii) Principal Markets and Distribution Methods**

The principal markets in which the Liberty Power Group operates hydroelectric generating facilities in Canada are Alberta, Ontario, New Brunswick and Québec. In the U.S., the principal market is Maine. The majority of generated hydroelectricity is conveyed from the relevant facility to the purchasers under the terms of long-term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser.

**(iii) Selected Facility**

(1) Tinker Hydro Facility

The Tinker Hydro Facility is located approximately 8 km north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The facility has a total nameplate capacity of approximately 34.5 MW.

As part of the generation assets in New Brunswick, the Corporation owns an electrical transmission system used to interconnect the Tinker Hydro Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/import capacity between Maine and New Brunswick.

The output of the Tinker Hydro Facility is actively marketed together with any applicable environmental attributes less any associated transportation costs. Additional energy and applicable environmental attributes are purchased from the market to supplement the energy generated from the Tinker Hydro Facility in order to service customer demand.

## Thermal (Cogeneration) Electric Generating Facilities

**(i) Production Method**

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods.

**(ii) Principal Markets and Distribution Methods**

The principal markets for the Corporation's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to ISO rules. In addition to grid sales of electricity and power, electricity and thermal energy are also sold to onsite or adjacent third-party thermal host facilities for use in production.

**(iii) Selected Facilities**

(1) Sanger Thermal Facility

The Sanger thermal cogeneration facility is a 56 MW natural gas-fired generating facility located in Sanger, California. The facility has a firm capacity agreement with an investor-owned utility expiring in 2021. The agreement calls for delivery of 38 MW of firm capacity.

(2) Windsor Locks Thermal Facility

The Windsor Locks thermal cogeneration facility (the "**Windsor Locks Thermal Facility**") is a 71 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Thermal Facility supplies thermal steam energy and a portion of electrical generation to Ahlstrom Corporation pursuant to a ground lease and an energy services agreement. Payments under the energy services agreement are fully indexed to the cost of natural gas consumed by the Windsor Locks Thermal Facility. The additional installed capacity at the site is committed to the ISO-NE market in the day ahead energy market, and the capacity and reserve markets as appropriate.

## Business Development

**(i) Strategy**

The business development group works to identify, develop and construct new power generating facilities and transmission lines, as well as to identify and acquire existing projects that would be complementary and accretive to the Liberty Power Group's existing portfolio. The business development group is committed to working proactively with all stakeholders including local communities. The Liberty Power Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include securing revenue certainty, 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.

**(ii) Principal Market Environment**

The Liberty Power Group believes that future opportunities for power generation projects will continue to develop as new targets are set for renewable and other clean power generation projects.

Within Canada, the market is driven largely by provincial regulations, of which Alberta and Saskatchewan are expected to present the most immediate opportunities. The AESO was commissioned by the Government of Alberta to develop recommendations for the procurement of renewable sources of power that will allow the Province to meet its objective to have 30% of electricity generation by 2030 come from renewable sources. One round of procurements was completed in 2017 and another solicitation was completed in 2018. Additional smaller procurement opportunities will continue to be considered, such as the 2018 solar procurement process with Alberta Infrastructure.

In Saskatchewan, the vertically-integrated utility SaskPower has set a target of 50% of generation capacity to come from renewables by 2030, which is expected to lead to the development of approximately 1,600 MW of new wind energy generation and 120 MW of utility-scale solar generation. The first competition commenced in 2017, with contracts awarded in 2018. The second round of procurement was initiated in May 2018, with a contract awarded in October 2018.

Within the United States, the most notable stimulus for the development of renewable power is the federal renewable electricity PTCs, a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, and the federal investment tax credit, a tax credit for qualified renewable energy facilities based upon a percentage of eligible capital costs. On December 18, 2015, the United States Congress approved a five-year extension to the 30% federal investment tax credit for solar energy properties and 2.3 cents (US$) per kilowatt-hour PTC (subject to certain inflation adjustments) for wind facilities, in each case subject to a phase-down. For solar projects that are completed by the end of 2023, the federal investment tax credit will remain at 30 percent for projects on which construction is commenced prior to the end of 2019, before it phases down to 26% and 22% for projects on which construction is commenced in 2020 and 2021, respectively. For solar projects on which construction is commenced after 2021, or that are placed in service after 2023, the federal investment tax credit will be 10 percent. The PTC for wind energy was maintained at 2.3 cents (US$) per kilowatt-hour (subject to certain inflation adjustments) for projects on which construction was commenced prior to the end of 2016 before phasing down 20 percent per year and being eliminated at the end of 2019. Federal tax reform passed late in 2017 had no direct impact on these incentive programs.

Additionally, other incentives continue to be offered independently for the development of renewable sources of power at the state and local levels. State policies continue to be driven by RPS, which vary between states. As of early 2019, 29 states plus Washington D.C. and three territories have adopted binding RPS targets, and eight additional states and one territory have taken on voluntary renewable portfolio goals. Approximately half of the binding targets range from 15% to 25% of retail sales to be achieved by specified dates between 2015 and 2025, and approximately half of the binding targets range from 25% to 60% of retail sales to be achieved by specified dates between 2025 and 2040.

The Liberty Power Group will continue to pursue development projects which provide the opportunity to exhibit accretive growth within these markets.

**(iii) Current Development Projects**

The Liberty Power Group's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs and/or hedging arrangements. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and projected investment returns that meet or exceed APUC's investment return criteria.

(1) Sugar Creek Wind Project

The Sugar Creek Wind Project is a 202 MW wind power electric generating development project located in Logan County, Illinois. Development of the project is underway, having secured long-term energy offtake via a 10-year financial hedge and 15-year REC contracts. An initial agreement has been entered into to secure construction services for the project, with a definitive agreement expected during the first quarter of 2019. Initial payment has been made for project turbines for an anticipated delivery to site in the second quarter of 2020, and a turbine supply agreement for the project is expected to be signed in the first quarter of 2019. The expected COD for the project is in the fourth quarter of 2020.

(2) Blue Hill Wind Project

The Blue Hill wind project is a 177 MW wind powered electric generating development project located in the rural municipalities of Lawtonia and Morse in southwest Saskatchewan (the "**Blue Hill Wind Project**"). All of the energy from the project will be sold to SaskPower pursuant to a 25 year PPA.

Ministerial approval to proceed with the development of the Blue Hill Wind Project was received from the Saskatchewan Ministry of Environment. The Blue Hill Wind Project has also received development permits from the municipalities of Lawtonia and Morse.

Based on the recently completed system impact study for the Blue Hill Wind Project, the expected time frame for design and construction is 24 to 36 months. SaskPower has commenced the facilities study phase of the interconnection procedures required to connect the Blue Hill Wind Project to SaskPower's transmission system. A geotechnical evaluation of the Blue Hill Wind Project site, including existing infrastructure and municipal roads, has been completed.

The current project execution plan estimates the COD for the Blue Hill Wind Project to be late 2021 or early 2022.

(3) 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 near Québec City (the "**Val-Éo Wind Project**"). The Liberty Power Group holds a 50% interest in the Val-Éo Wind Project through a partnership created with the Val-Éo Wind Cooperative (a community based landowner consortium).

The Liberty Power Group has a 50% equity interest in the project. It is expected 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 C$16 million.

The project will be developed in two phases. Phase I of the project is expected to be completed in 2019 and is expected to have a total capacity of 24 MW, with all energy from Phase I of the project to be sold to Hydro-Québec Distribution pursuant to a 20-year PPA. Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements. All land agreements, construction permits and authorizations have been obtained for Phase I, except for final approval from Transport Canada and an agricultural land use permit expected in the first quarter of 2019.

(4) Walker Ridge Wind Project

The Walker Ridge Wind Project is a 144 MW wind power electric generating facility located in the counties of Lake and Colusa in northern California. The facility will be located on U.S. Bureau of Land Management land. The interconnection agreement was executed with the California Independent System Operator and Pacific Gas and Electric Company in December 2018. Work is ongoing with respect to site design, environmental permitting and EPC engagement. Energy from the project is expected to be sold pursuant to a long-term financial hedge. The expected COD for the project is late 2020 or 2021.

(5) Broad Mountain Wind Project

The Broad Mountain Wind Project is a 200 MW wind power electric generating facility located in Carbon County, Pennsylvania. Development of the project is planned to be completed in two phases. Phase I, representing installed capacity of 80 MW, is targeted for completion in 2020, pending regulatory approvals. The balance of the 120 MW of proposed capacity is targeted for completion in 2022. The Broad Mountain Wind Project has secured the majority of land leases required, and environmental and interconnection studies are underway including geotechnical investigations, FAA permits and zoning applications for Phase I. Energy from Phase I of the project is expected to be sold pursuant to a long-term financial hedge and/or PPAs to local end users.

(6) Shady Oaks II Wind Project

The Shady Oaks II wind project is a 120 MW expansion of the Liberty Power Group's operational Shady Oaks Wind Facility, located in Lee County, Illinois (the "**Shady Oaks II Wind Project**"). The Shady Oaks II Wind Project is expected to be located on land adjacent to the existing Shady Oaks Wind Facility, and, subject to interconnection studies that are currently in progress, will connect to the same point of interconnection. Work on environmental permitting and site design are ongoing. Energy from the expansion project is expected to be sold pursuant to a long-term financial hedge. The expected COD for the project is late 2020 or 2021.

(7) Sandy Ridge II Wind Project

The Sandy Ridge II wind project is a 60 MW to 100 MW expansion of the Liberty Power Group's operational Sandy Ridge Wind Facility, located in Centre County, Pennsylvania (the "**Sandy Ridge II Wind Project**"). The Sandy Ridge II Wind Project is expected to be located on land adjacent to the existing Sandy Ridge Wind Facility, and, subject to interconnection studies that are currently in progress, will connect to the same point of interconnection. Work on environmental permitting and site design is ongoing. Energy from the expansion project is expected to be sold pursuant to a long-term financial hedge. The expected COD for the project is late 2020 or early 2021.

(8) Great Bay II Solar Project

The Great Bay II solar project (the "**Great Bay II Solar Project**") is an approximately 45 MW expansion of the Liberty Power Group's operational Great Bay II Solar Project, located in Somerset County, Maryland. The project is expected to be located on land nearby the existing Great Bay Solar Facility, and will connect to the same point of interconnection. Work on environmental permitting and site design is ongoing. Energy from the expansion project is expected to be sold pursuant to a long-term financial hedge. The expected COD for the project is late 2019 or early 2020.

**(iv) Future Development Projects – Greenfield Projects**

The Corporation continues to pursue new development opportunities in addition to building upon an existing portfolio of green-field sites. These projects represent a diversified range of opportunities within wind, solar, hydro and natural gas modes of generation and are located throughout North America and internationally.

### Renewable Energy Credits

A REC is a non-tangible, tradable commodity that represents the environmental attributes of one MWh of electricity generated from a renewable (such as wind and solar) or other eligible source. RECs are used by utilities for RPS compliance where required, and are used by corporations, universities, governmental agencies and other parties to evidence their commitment to sustainable energy. The RPS mandates are set at a state level and stipulate a certain amount of electricity to be generated from renewable sources by a specific year.

Currently, the Minonk, Sandy Ridge, Senate and Shady Oaks Wind Facilities, and the Great Bay Solar Facility, each produce and sell RECs through bilateral contracts. The Liberty Power Group is also party to three separate REC agreements with respect to renewable energy attributes to be produced at the Sugar Creek Wind Project once commercial operation is achieved.

In the State of Connecticut, certain thermal energy facilities are eligible for Class III CT RECs, a portion of which must be contributed to a state-mandated energy efficiency and load management investment plan implemented by Connecticut utilities. Currently, the Windsor Locks Thermal Facility is qualified for Class III CT RECs for a portion of its production and is entitled to retain 75% of such Class III RECs, resulting in retention of 1 REC per 1.33 MWh of the eligible production. The Windsor Locks Thermal Facility sells the RECs that it is permitted to retain through bilateral contracts.

## 3.1.2 Specialized Skill and Knowledge

The Liberty Power Group's employees have extensive experience in the independent power industry in Canada and the United States. The production of energy from all facilities requires specialized skill and knowledge in relation to such facilities and their component parts, and the Liberty Power Group employs various personnel, and occasionally uses outside contractors, who have such skill and knowledge.

### 3.1.3 Competitive Conditions

Deregulation has increased the demand for privately generated power from a variety of sources, including fossil fuels, waste, wind, water and solar. With deregulation and opening of competition in the electricity marketplace, there may be an increased opportunity for the energy customer to choose the type of generation producing the electricity.

The U.S. Department of Energy has found that many utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The Department of Energy believes that as deregulation and open competition evolve, the green power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric, wind and solar power is generally not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of renewable power generally does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Taking into account capital costs, wind and solar power has generally been more expensive than traditional forms of generated power. However, in recent years costs have decreased with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, investment tax incentives, RPS and improved equipment capacity factors, both wind and solar energy have achieved parity with market pricing for electricity in many jurisdictions.

The Liberty Power Group believes that future opportunities for power generation projects will continue to arise given that many jurisdictions continue to increase targets for renewable and other clean power generation projects.

The Liberty Power Group is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources.

### 3.1.4 Cycles and Seasonality

#### (i) Hydroelectric Generating Facilities

The Liberty Power 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.

#### (ii) Wind Power Generating Facilities

The Liberty Power Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall through spring period, 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.

#### (iii) Solar Power Generating Facilities

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

## 3.2 Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of rate-regulated utilities throughout the United States that, as at December 31, 2018, provided distribution services to approximately 768,000 connections in the natural gas, electric, water and wastewater sectors, with an approximate regional breakdown as follows.

| | West | Central | East |
|---|---|---|---|
| Natural gas distribution | - | 127,000 | 211,000 |
| Electrical distribution | 49,600 | 172,500 | 43,900 |
| Water distribution | 94,000 | 26,000 | - |
| Wastewater collection | 42,000 | 2,000 | - |
| **Total** | 185,600 | 327,500 | 254,900 |

The regulated electrical distribution utility systems and related generation assets are located in the states of Arkansas, California, Kansas, Missouri, New Hampshire, and Oklahoma. The regulated natural gas distribution utility systems are located in the states of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri. The regulated water distribution and wastewater collection utility systems are located in the states of Arizona, Arkansas, California, Illinois, Missouri and Texas. The Liberty Utilities Group also owns and manages generating assets with a gross capacity of approximately 1.7 GW and has investments in a further approximately 0.3 GW of net generation capacity.

Details with respect to significant Liberty Utilities Group regulated facilities and certain rate and tariff information is set out in Schedules C, D and E to this AIF.

### 3.2.1 Description of Operations

#### Water Distribution and Wastewater Collection Systems

##### (i) Method of Providing Services and Distribution Methods

A water utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in federal and state regulations and which are typically administered and enforced by a state or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility. The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fees and reconnects.

A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation. The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as “effluent”, is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facility’s operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on federal and state regulations which are administered, and continuing compliance is enforced by the state agency to which federal enforcement powers are delegated.

**(ii) Principal Markets and Regulatory Environments**

The Liberty Utilities Group's water and wastewater facilities are located in the United States in the states of Arizona, Texas, Illinois, Missouri, Arkansas and California. The water and wastewater utilities are generally 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 procedures, issuance of securities, acquisitions and other matters. These utilities generally operate under cost-of-service regulation as administered by these state authorities. The utilities generally use a historic or forward-looking test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on each of its water and wastewater utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. Rates are approved by the agency to provide the utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

**(iii) Selected Facilities**

(1) Liberty Utilities (Litchfield Park Water & Sewer) Corp. Water & Wastewater Systems

The LPSCo System, located in and around the city of Goodyear 15 miles west of Phoenix, Arizona has a service area that includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County. The wastewater system's Palm Valley Water Reclamation Facility has permitted treatment capacity of 6.5 million gallons per day.

(2) Liberty Park Water System

Liberty Park Water owns and operates two regulated water utilities engaged in the production, treatment, storage, distribution and sale of water in Southern California. Liberty Park Water provides, owns and operates the water system in central Los Angeles. Liberty Utilities (Apple Valley Ranchos Water) Corp. (wholly-owned by Liberty Park Water) owns and operates the water system in Apple Valley.

## Electric Distribution Systems

**(i) Method of Providing Services and Distribution Methods**

Electric distribution is the final stage in the delivery system of providing electricity to end users. An electric distribution utility sources and distributes electricity to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customers where the voltage is again lowered through a transformer for use by the customer.

The rates charged for electric distribution service are comprised of a fixed charge that recovers customer related costs, such as meter readings, and a variable rate component that recovers the cost of generation, transmission and distribution. Other revenues are comprised of fees for other services such as establishing a connection, late fee, reconnections, and energy efficiency programs.

The electrical distribution utilities located in Arkansas, California, Kansas, Missouri, New Hampshire and Oklahoma are subject to state regulation and rates charged by these utilities must be reviewed and approved by their respective state regulatory authorities.

**(ii) Principal Markets and Regulatory Environments**

The Liberty Utilities Group operates electrical distribution systems in the states of Arkansas, California, Kansas, Missouri, New Hampshire and Oklahoma under a cost-of-service methodology. The utilities use either an historical test year, adjusted pro-forma for known and measurable changes, in the establishment of their rates, or prospective test years based on expenses expected to be incurred in future periods, which is the methodology utilized in California. Pursuant to these methods, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses and administrative and general expenses.

Rate cases ensure that a particular utility recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the utility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments. In the case of the CalPeco Electric System, a rate case filing is mandatory every three years.

**(iii) Selected Facilities**

(1) CalPeco Electric System

The CalPeco Electric System provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. CalPeco Electric System's connection base is primarily residential. Its commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores.

The Corporation has entered into a multi-year services agreement with NV Energy that commenced in January 2016. The services agreement obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, when combined with the output of the Luning Solar Facility and another solar facility, satisfy the current California Renewables Portfolio Standard requirement for the term of the services agreement. The CalPeco Electric System has received approval from CPUC to recover the costs it will incur under this agreement. The CalPeco Electric System has authorization for rate recovery of the costs that the CalPeco Electric System has or will incur to acquire, own and operate the Luning Solar Facility. On January 31, 2017, the Federal Energy Regulatory Commission authorized transactions between the Luning Solar Facility and the CalPeco Electric System pursuant to the services agreement with NV Energy. The CalPeco Electric System is also subject to FERC regulation.

(2) Granite State Electric System

The Granite State Electric System provides distribution service in southern and northwestern New Hampshire, centered around operating centres in Salem in the south and Lebanon in the northwest. The Granite State Electric System's customer base consists of a mixture of residential, commercial and industrial customers.

The Granite State Electric System is required to provide electric commodity supply for all customers who do not choose to take supply from a competitive supplier ("**Default Service**") in the New England power market and is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. The Granite State Electric System must file with the NHPUC twice a year to adjust for market prices of power purchased and is also subject to FERC regulation.

(3) Empire District Electric System

Based in Joplin, Missouri, Empire is a regulated utility providing electric, natural gas and water service in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, it provides water service to three towns in Missouri. The vertically-integrated regulated electricity operations of Empire represent the majority of its operating revenues and assets. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity. Empire also operates a fibre optics business. The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and the FERC.

## Natural Gas Distribution Systems

**(i) Method of Providing Services and Distribution Methods**

Natural gas is a fossil fuel composed almost entirely of methane (a hydrocarbon gas) usually found in deep underground reservoirs formed by porous rock. In making its journey from the wellhead to the customer, natural gas may travel thousands of miles through interstate pipelines owned and operated by pipeline companies. Along the route, the natural gas may be stored underground in depleted oil and gas wells or other natural geological formations for use during seasonal periods of high demand. Interstate pipelines interconnect with other pipelines and other utility systems and offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the FERC. Typically, the distribution network operates pipelines (including transmission and distribution pipelines), gate stations, district regulator stations, peak shaving plants and natural gas meters. The gas distribution utilities owned by the Liberty Utilities Group are subject to state regulation and rates charged by these facilities may be reviewed and altered by the state regulatory authorities from time to time.

**(ii) Principal Markets & Regulatory Environments**

The Liberty Utilities Group owns and operates natural gas distribution systems, under cost-of-service regulation in the states of Illinois, Iowa, Missouri, Georgia, Massachusetts and New Hampshire. The natural gas utilities use a test year to determine distribution rates for the utility. Pursuant to this method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses, and administrative and general expenses.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments.

**(iii) Selected Facilities**

(1) EnergyNorth Gas System

The EnergyNorth Gas System is a regulated natural gas utility providing natural gas distribution services in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord. The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

In its rate case completed during 2018, the rates of the EnergyNorth Gas System were authorized to be decoupled, which means that, going forward, fluctuations in weather will have less impact on revenues.

(2) Empire District Gas System

EDG is engaged in the distribution of natural gas in Missouri. A PGA allows EDG to recover from its customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with EDG's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA allows EDG to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

(3) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, and Hamilton. The Peach State Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

The Peach State Gas System's rates are reviewed and updated annually through a tariff provision called the Georgia Rate Adjustment Mechanism. This mechanism allows for the annual review of cost recoveries and the setting of rate base returns with a target of 10.7% return on equity and a range of 10.5% to 10.9%. The Peach State Gas System also files an annual Pipe Replacement Program revision to adjust the rates collected for capital costs incurred to replace cast iron and bare steel pipe in its system.

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). The PGA requires a change in rates at least every three months.

(4) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services in six communities located in the southeastern portion of Massachusetts. The New England Gas System's customer base consists of a mixture of residential, commercial, and industrial customers.

The cost of gas is fully recoverable from customers through the Gas Adjustment Factor (" **GAF**") when billed to "firm" gas customers included in approved tariffs by the MDPU. The GAF is adjusted twice annually and more frequently under certain circumstances.

(5) Midstates Gas Systems

The Midstates Gas Systems own regulated natural gas utilities providing natural gas distribution services to approximately 190 communities in the states of Illinois, Iowa and Missouri, with a mix of residential, commercial, industrial and transportation customers. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri.

Illinois allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the calendar year. Iowa allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the twelve months ended August of each year. Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted annually (in fourth quarter) with allowance to file quarterly.

## Natural Gas and Electric Transmission

### (i) Method of Providing Services and Transmission Methods

Pipelines offer a variety of services under their FERC tariffs to include firm and interruptible transportation, along with other services to provide commercial markets additional flexibility. Some examples of these types of services would be park and loan, pooling and balancing services. In addition, firm service tariff features would also provide additional features to support secondary market activity to include, but not limited to capacity assignment, capacity releases, segmentation and renewal options.

### (ii) Principal Markets & Regulatory Environments

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certifies all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an OATT and publicly post capacity available for transportation, and the agency periodically reviews, under just and reasonable standards, the tariff rates to be charged by the certificate holder. In addition, the FERC prescribes operating and safety standards to be followed along with other federal agencies such as Department of Transportation and the Occupational Safety and Health Administration.

### (iii) Selected Facilities

(1) Empire Transmission Facilities

The Empire electric transmission facilities are located within a four state area of Missouri, Kansas, Oklahoma and Arkansas and primarily consist of 22 miles of 345 kV lines, 405 miles of 161 kV lines, 750 miles of 69 kV lines and 82 miles of 34.5 kV lines.

Empire is a member of the SPP which spans an area from the Canadian border in Montana and North Dakota in the north to parts of New Mexico, Texas and Louisiana in the south. The transmission facilities are offered for service under an OATT approved by the FERC and administered by SPP. Service requests are placed in the SPP Open Access Same-Time Information System (OASIS) and is evaluated by SPP for available capacity. SPP determines who is offered available transmission capacity subject to the SPP Tariff and SPP Market Rules and is offered on a non-discriminatory basis. Service requests can be either point-to-point or network service, where network service is used for serving electric load. Empire is subject to four different states regulatory bodies, the SPP regional entity for NERC compliance, SPP Market Rules, and the FERC.

## Business Development

The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria.

(1) Granite Bridge Project

The Liberty Utilities Group is developing the Granite Bridge project in New Hampshire (the " **Granite Bridge Project**"), which has been conceived to help relieve supply constraints impacting the Liberty Utilities Group's natural gas distribution customers in order to reduce customer gas energy costs and support continued economic growth. The Granite Bridge Project is comprised of a proposed 26 mile lateral natural gas pipeline, connecting the Portland Natural Gas Transmission System, the Maritimes & Northeast Pipeline (Joint Facilities) and the Tennessee Gas Concord Lateral to the Liberty Utilities Groups' New Hampshire distribution system. The pipeline will be constructed in a designated energy infrastructure corridor along Route 101 in New Hampshire. In addition, the project includes a proposed 2 bcf full containment storage tank and liquefaction and vaporization equipment, all of which will be located in an abandoned quarry to minimize visual impact to the host community of Epping, New Hampshire.

The Liberty Utilities Group filed for approval of its plan to construct the Granite Bridge Project with the NHPUC in December 2017, and a decision is expected in 2019.

The Liberty Utilities Group has commenced environmental, geotechnical and survey work on the Granite Bridge Project, and has received preliminary acceptance from the New Hampshire Department of Transportation on its proposed pipeline route. The Manchester, Hudson, Nashua, and Concord Chambers of Commerce have publicly endorsed the Granite Bridge Project, together with the New Hampshire Building Trades. In addition, a bipartisan group of 22 State senators has publicly endorsed the project.

The development and construction costs of the Granite Bridge Project are expected to be included in the rate base of the EnergyNorth Natural Gas System.

A final investment decision will be made following receipt of NHPUC and New Hampshire Site Evaluation Committee approvals .

(2) Mid-West Wind Development Project

In 2017, the Liberty Utilities Group presented a plan to the MPSC for an investment in up to 600 MW of strategically located wind energy generation which is forecast to reduce energy costs for its customers. On July 11, 2018, an order was received from the MPSC supporting various requests related to the proposed investment plan.

Effective October 11, 2018, Empire entered into purchase agreements with a developer for two wind development projects, North Fork Ridge and Kings Point, and effective November 16, 2018, entered into a third purchase agreement with another developer for Neosho Ridge, with total combined capacity of 600 MW. The agreements contain development milestones and termination provisions that primarily apply prior to the commencement of construction. Agreements have also been executed for the design and construction of the projects. These projects are located in Kansas and Missouri, within the Empire District Electric System service territory, and are expected to begin construction in the second half of 2019, subject to the receipt of certain regulatory approvals. The estimated construction cycle for the projects is 12 to 18 months.

The proposed new wind generating capacity is forecast to generate approximately 2,400 GW-hrs of energy per year for consumption by Empire District Electric System customers.

The development and construction costs of the three projects comprising the 600 MW plan, net of third-party tax equity investment sought to efficiently use the tax attributes from the projects, are expected to be included in the rate base of Empire District Electric System. The cost of energy from the projects is forecast to result in energy costs savings for Empire District Electric System customers.

### 3.2.2 Specialized Skill and Knowledge

The Liberty Utilities Group requires specialized knowledge of its utility systems, including electrical, gas, water and wastewater. Upon acquiring a new utility system, the Liberty Utilities Group will typically retain the existing employees with such specialized skill and knowledge. In addition, the Liberty Utilities Group will add, when required, additional trained utility personnel at its corporate offices to support the expanded portfolio of utility assets.

### 3.2.3 Competitive Conditions

The Liberty Utilities Group's utility businesses have geographic monopolies in their service territories. The Liberty Utilities Group has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. The Liberty Utilities Group believes that the relationship with regulators is unique to each state and therefore is best delivered by local managers who work in the service territory. The local regulatory teams meet with regulatory agencies on a regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives.

### 3.2.4 Cycles and Seasonality

#### (i) Water and Wastewater Systems

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 Corporation attempts to mitigate the seasonal and weather-related risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, for the Central Basin and Apple Valley facilities in California, a weather normalization adjustment is applied to customer bills that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

#### (ii) Electricity Systems

The CalPeco Electric System's demand for energy sales are primarily affected by weather conditions. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. The CalPeco Electric System has implemented a BRRBA rate mechanism that removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power and the ECAC deferral) to a fixed monthly amount. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

The Granite State Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with New England weather. The competitive market for power supply is managed by the ISO-NE. The Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers.

The Empire District Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with weather in its service territory. The Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers and as a result does not have a material financial impact.

#### (iii) Natural Gas Systems

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial and industrial customers. The colder the weather, the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems' demand profiles typically peak in the winter months of January and February and decline 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 Liberty Utilities Group attempts to mitigate the above noted fluctuations 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, EnergyNorth Gas System and Midstates Gas Systems, a weather normalization adjustment is applied to customer bills that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Most regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate gas demand fluctuations.

## 3.3 International Development Activities

As a component of the acquisition of its interest in Atlantica, the Corporation secured an opportunity for AAGES to evaluate participation in a number of development opportunities which had been previously advanced by Abengoa. Since its formation in the first quarter of 2018, the AAGES development team has been actively evaluating international projects.

The AAGES development team works to identify, develop and construct new clean energy and water projects, as well as to identify and acquire operating projects that would be complementary and accretive based on the Corporation's investment criteria.

As described above under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate", AAGES has entered into a definitive agreement to acquire ATN3, the owner of the ATN3 Project in Peru. The ATN3 Project will be operated under a concession agreement with the government of Peru, with an operating period of 30 years from the commencement of commercial operation and which grants to ATN3 an annual fixed tariff denominated in U.S. dollars and indexed to the U.S. consumer price index. Ownership of the ATN3 Project will be transferred to the government of Peru at the end of the 30-year concession term.

## 3.4 Principal Revenue Sources

APUC owns, directly or indirectly, interests in renewable generation facilities, thermal generation facilities, electricity distribution utilities, natural gas and propane distribution utilities, and water distribution and wastewater utilities.

The following provides a breakdown of the Corporation's total revenue by percentage for the years ended December 31, 2017 and December 31, 2018:

| | % Total Revenue | |
|---|---|---|
| | **December 31, 2017** | **December 31, 2018** |
| Non-regulated energy sales | 14.3 % | 14.3 % |
| Utility electricity sales & distribution | 50.2 % | 50.5 % |
| Utility natural gas sales & distribution | 24.8 % | 26.1 % |
| Utility water distribution and wastewater treatment sales & distribution | 9.2 % | 7.8 % |
| Other revenue[1] | 1.5 % | 1.3 % |

1 Other revenue includes gas transportation and RECs.

The purchase of electricity and natural gas by the Corporation's electricity distribution and natural gas distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the Corporation uses Net Energy Sales for the Liberty Power Group (see "Non-GAAP Financial Measures") and Net Utility Sales for the Liberty Utilities Group (see "Non-GAAP Financial Measures") as a more appropriate measure of the results. Adjusting for the impact of these commodity costs, the following provides a breakdown of the Corporation's Net Energy Sales and Net Utility Sales by percentage for the years ended December 31, 2017 and December 31, 2018:

| | % Net Energy Sales/Net Utility Sales | |
|---|---|---|
| | **December 31, 2017** | **December 31, 2018** |
| Non-regulated energy sales | 17.5 % | 17.9 % |
| Utility electricity sales & distribution | 47.9 % | 48.7 % |
| Utility natural gas sales & distribution | 20.8 % | 21.3 % |
| Utility water distribution and wastewater treatment sales & distribution | 11.6 % | 10.3 % |
| Other revenue[1] | 2.2 % | 1.8 % |

1 Other revenue includes gas transportation and RECs.

For the Liberty Power Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2017 and December 31, 2018:

| | % Revenue | |
|---|---|---|
| | **December 31, 2017** | **December 31, 2018** |
| Wind generation | 57.1 % | 54.0 % |
| Solar generation | 4.7 % | 7.0 % |
| Hydroelectric generation | 19.3 % | 17.2 % |
| Thermal generation | 13.0 % | 17.0 % |
| Other revenue[1] | 5.9 % | 4.8 % |

1 Other revenue includes RECs.

For the Liberty Utilities Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2017 and December 31, 2018:

| | % Revenue | |
|---|---|---|
| | **December 31, 2017** | **December 31, 2018** |
| Utility electricity sales & distribution | 59.1 % | 59.4 % |
| Utility natural gas sales & distribution | 29.1 % | 30.6 % |
| Utility water distribution and wastewater treatment sales & distribution | 10.9 % | 9.2 % |
| Other revenue[1] | 0.9 % | 0.8 % |

1 Other revenue includes gas transportation.

## 3.5 Environmental Protection

The Corporation's businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licenses, permits, standards, policies and legislation. Failure to operate such businesses in strict compliance with these regulatory standards may expose them to citations, claims, clean-up costs, penalties, and loss of operating licenses and permits.

The Corporation has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters, and environmental and compliance departments with responsibility for monitoring the Corporation and its subsidiaries' operations.

Environmental protection requirements did not have a significant financial or operational effect on the Corporation's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2018. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets, such as those described elsewhere in this AIF, are expected to increase the earnings and benefit the competitive position of the Corporation.

The Corporation faces 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 (see "Enterprise Risk Factors – Risks Relating to Operations").

## 3.6 Employees

The Corporation's executive management group consists of nine individuals. As at December 31, 2018, the Corporation employed a total of 2,277 people.

The Liberty Power Group employed a total of 156 people as at December 31, 2018. All of the employees of the Liberty Power Group are non-unionized.

The Liberty Utilities Group employed a total of 1,859 people as at December 31, 2018. The Liberty Utilities Group employees are non-unionized with the exception of: 65 employees at the CalPeco Electric System, 40 employees at the Midstates Gas Systems, 322 employees at Empire, 191 employees at the EnergyNorth Gas System and Granite State Electric System, and 87 employees at the New England Gas System.

As at December 31, 2018, the corporate and shared services groups consisted of an additional 177 people located at the corporate offices in Oakville, Ontario and an additional 82 shared services employees located throughout the United States.

## 3.7 Foreign Operations

For the twelve months ended December 31, 2018, 100% of the revenue of the Liberty Utilities Group and approximately 72% of the revenue of the Liberty Power Group was generated from operations located in the United States.

## 3.8 Economic Dependence

The Corporation does not believe it is substantially dependent on any single contractual agreement or set of related agreements.

## 3.9 Social and Environmental Policies and Commitment to Sustainability

The Corporation is committed to advancing a sustainable energy and water future. The Corporation aims to be a top quartile global utility, known for its dedication to safety and reliability, customer experience, employee engagement, community inclusion, environmental and social responsibility and financial performance.

Corporate responsibility is often defined by a company's philosophy to operate in an economically, socially and environmentally sustainable manner, while recognizing the interests of its stakeholders. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments and business partners. The Corporation has formal policies and procedures that support its commitment to corporate responsibility.

**Social Responsibility**

The Corporation's Code of Business Conduct and Ethics is the foundation of the Corporation's corporate responsibility framework. All directors, officers, employees, agents and contractors are required to read the Code of Business Conduct and Ethics and apply the code to their work. Employees are required to complete an annual online test which confirms their compliance with and understanding of the Code of Business Conduct and Ethics.

The economic branch of the Corporation's social responsibility efforts incorporates local spending, local hiring and operational efficiency. The Corporation's commitment to people is demonstrated through its employee training, learning and development programs, organizational improvements, emergency management programs and community involvement. Policies in place that support the Corporation's commitment to social responsibility include its Diversity Policy, Whistleblower Policy and Supplier Code of Conduct.

**Environmental, Health and Safety**

The Corporation's businesses have safety and environmental compliance policies in place. These policies have been communicated with staff and have been incorporated into their respective Safety Mission Statements and employee manuals. The Corporation's Environmental and Health and Safety Groups are responsible for developing environmental and safety policies, developing and facilitating environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits. The Corporation is in the process of implementing an environmental management system designed to provide for the continuous measurement, evaluation and improvement of the Corporation's management of its environmental compliance, risks and performance. The Corporation has environmental programs in place that promote energy efficiency and responsible water usage, help facilitate habitat conservation to minimize impact, monitor greenhouse gas emissions and promote waste reduction and spill prevention.

**Sustainability Policy**

In September 2018, the Corporation adopted a Sustainability Policy outlining the sustainability principles that are core to its business. The Sustainability Policy is aligned with the United Nations' Sustainable Development Goals (SDGs), namely Good Health and Well-Being (SDG3), Gender Equality (SDG5), Clean Water and Sanitation (SDG6), Affordable and Clean Energy (SDG7), Decent Work and Economic Growth (SDG8), Sustainable Cities and Communities (SDG11) and Climate Action (SDG13). By embedding these tenets into its decision making, the Corporation is committed to building and operating its business such that it makes a positive and durable contribution to a sustainable energy and water future.

## 3.10 Credit Ratings

The following chart shows credit ratings issued to the Corporation and currently in effect: [1]

| | S&P | DBRS | Fitch | Moody's |
|---|---|---|---|---|
| APUC - Issuer rating | BBB | BBB | BBB | - |
| APUC - Preferred Shares | P-3 (high) | Pfd-3 | - | - |
| APUC - Subordinated Notes | BB+ | | BB+ | |
| APCo - Issuer rating | BBB | BBB | BBB | - |
| APCo - Senior unsecured debt | BBB | BBB | - | - |
| Liberty Utilities Co. - Issuer rating | BBB | - | BBB | - |
| Liberty Utilities Finance GP1 - Issuer rating [2] | - | BBB (high) | - | - |
| Liberty Utilities Finance GP1 - Senior unsecured notes | - | BBB (high) | BBB+ | - |
| Empire - Issuer rating | BBB | - | - | Baa1 |
| Empire - First mortgage bonds | - | - | - | A2 |
| Empire - Senior unsecured debt | - | - | - | Baa1 |
| Empire - Commercial paper | - | - | - | P-2 |

1 Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. Credit ratings are not a recommendation to buy, sell or hold securities of APUC or any of its subsidiaries and do not comment as to market price or suitability for a particular investor. There can be no assurance that a rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn at any time by the rating agency.

2 Issued by Liberty Utilities Finance GP1 and guaranteed by Liberty Utilities Co.

### S&P

S&P rates long-term debt instruments and issuers with ratings ranging from "AAA", which represents an extremely strong capacity of an obligor to meet its financial commitment, to "D", which means that, in the case of an issue rating, that the issuer is in default or in breach of an imputed promise, and in the case of an issuer rating, that there is a general default and the obligor will fail to pay all or substantially all of its obligations as they become due. A rating of "BBB" by S&P denotes an obligor having adequate capacity to meet its financial commitments; however, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments. A rating of "BB" by S&P is included amongst a range of ratings determined to have significant speculative characteristics. An obligation rated "BB" is less vulnerable to nonpayment than other speculative issues; however, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor having inadequate capacity to meet its financial commitments. S&P ratings from "AA" to "CCC" may be modified by the addition of a plus "+" or minus "-" sign to show relative standing within the major rating categories. The absence of either a plus "+" or minus "-" sign indicates that the rating is in the middle of the category.

S&P's Canadian preferred share rating scale serves the Canadian financial markets by expressing preferred share ratings in terms of rating symbols that have been actively used in the Canadian market over a number of years. There is a direct correspondence between the specific ratings assigned on the Canadian preferred share scale and the various rating levels on S&P's global preferred share rating scale. S&P's Canadian preferred share rating scale ranges from "P-1", which represents a very strong capacity of an obligor to meet its financial commitments, to "P-5", which represents an obligation vulnerable to nonpayment and which is dependent upon favorable business, financial and economic conditions for the obligor to meet its financial commitments. A preferred share rating of "P-3 (high)" is equivalent to a rating of "BB+" on S&P's global scale (which is discussed above). Ratings from "P-1" to "P-5" may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

### DBRS

DBRS rates debt instruments and issuers with ratings ranging from “AAA”, which represents debt instruments and issuers of the highest credit quality, to “D”, which represents debt instruments for which an issuer has filed under any applicable bankruptcy, insolvency or winding up statute or for which there is a failure to satisfy an obligation after the exhaustion of grace periods. A rating of “BBB” by DBRS denotes an obligor having adequate credit quality; the capacity for the payment of financial obligations is considered acceptable although it may be vulnerable to future events. All rating categories other than “AAA” and “D” also contain subcategories “(high)” and “(low)”. The absence of either a “(high)” or “(low)” designation indicates that the rating is in the middle of the category.

The DBRS preferred share rating scale ranges from “Pfd-1”, which represents a superior credit quality, supported by entities with strong earnings and balance sheet characteristics, to “D”, which represents that an issuer has filed under any applicable bankruptcy, insolvency or winding up statute or is in default per the legal documents. Preferred shares rated “Pfd-3” are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. “High” or “low” grades are used to indicate the relative standing within a rating category. The absence of either a “high” or “low” designation indicates the rating is in the middle of the category.

### Fitch

Fitch rates long-term debt instruments and issuers with ratings ranging from “AAA”, which represents the highest credit quality and denotes the lowest expectation of default risk, to, in the case of rating for the debt instruments themselves, “C” which indicates exceptionally high levels of credit risk, or, in the case of issuer ratings, “D”, which indicates an issuer that in Fitch’s opinion has entered into bankruptcy filings, administration, receivership, liquidation or other formal winding-up procedure or that has otherwise ceased business. A rating of “BBB” by Fitch indicates that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. A rating of “BB” by Fitch indicates an elevated vulnerability to credit risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial alternatives may be available to allow financial commitments to be met. Ratings from “AA” to “CCC” may be modified by the addition of a plus “+” or minus “-” sign to show relative standing within the major rating categories. The absence of either a plus “+” or minus “-” sign indicates that the rating is in the middle of the category.

### Moody’s

Moody’s rates long-term debt instruments and issuers with ratings ranging from “Aaa”, which represents obligations judged to be of the highest quality, subject to the lowest level of credit risk, to “C”, which represents an obligation typically in default, with little prospect for recovery of principal or interest. A rating of “A” by Moody’s denotes obligations judged to be upper-medium grade and subject to low credit risk, while a rating of “Baa” by Moody’s denotes obligations judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. A Moody’s rating of “Aa” through “Caa” may be modified by the addition of numerical modifiers 1, 2 and 3 to show relative standing within the major rating categories. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Short-term obligations and issuers thereof may carry a rating ranging from Prime-1 or “P-1”, which represents an issuer’s superior ability to repay short-term debt obligations, to “Prime-3” or “P-3”, which represents an issuer’s acceptable ability to repay short-term obligations. Issuers may also be rated “Not Prime” or “NP”, which represents that an issuer does not fall within any of the Prime rating categories.

## 4. ENTERPRISE RISK FACTORS

The Corporation is subject to a number of risks and uncertainties, certain of which are described in more detail below. The actual effect of any event on the Corporation’s business could be materially different from what is anticipated or described below. The description of risks below does not include all possible risks. See APUC’s MD&A for the year ended December 31, 2018 for additional risks facing the Corporation.

Led by the Chief Compliance and Risk Officer, the Corporation has an established enterprise risk management, or ERM, framework. The Corporation's ERM framework follows the guidance of ISO 31000:2009 and the COSO Enterprise Risk Management – Integrated Framework. The Corporation's ERM framework is intended to systematically identify, assess and mitigate the key strategic, operational, financial and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's Board-approved ERM policy details the Corporation's risk management processes, risk appetite and risk governance structure.

As part of the risk management process, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board's Risk Committee periodically.

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

## 4.1 Risk Factors Relating to Operations

***The Corporation's operations involve numerous risks which, if they materialize, could disrupt or adversely affect its business, results of operations, financial position and cash flows.***

The Corporation's ability to safely and reliably operate, maintain, construct and decommission (as applicable) its power generation facilities, utility systems and other assets involve a variety of risks customary to the power and utilities sector, many of which are beyond the Corporation's control, including those that arise from:

- severe weather conditions and natural disasters;
- global climate change;
- environmental contamination/wildlife impacts;
- casualty or other significant events such as fires, explosions, security breaches or drinking water contamination;
- commodity supply and transmission constraints or interruptions;
- workplace and public safety events;
- loss of key personnel;
- labour disputes;
- poor employee performance/workforce effectiveness;
- demand (including seasonality);
- loss of key customers;
- reduction in the price received for goods/services;
- reliance on transmission systems and facilities operated by third parties;
- land use rights/access;
- critical equipment breakdown or failure;
- lower-than-expected levels of efficiency or operational performance;
- acts by third parties, including cyber-attacks, criminal acts, vandalism, war and acts of terrorism;
- opposition by external stakeholders, including local groups, communities and landowners;
- commodity price fluctuations;
- obligations to serve; and
- the Corporation's reliance on subsidiaries.

These and other operating events and conditions could result in service and operational disruptions and may reduce the Corporation's revenues, increase costs or both, and may materially affect its business, results of operations, financial position, valuation and cash flows, particularly if a situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery.

***The Corporation's generation, distribution and transmission utility assets may be negatively impacted by changes in general economic, credit, social and market conditions.***

The Corporation's generation, distribution and transmission utility assets are affected by energy demand in the jurisdictions in which they operate, that may change as a result of fluctuations in general economic conditions, energy prices, employment levels, personal disposable income and housing starts. Significantly reduced energy demand in the Corporation's service territories could reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe prolonged downturn in economic conditions may have an adverse effect on the Corporation's results of operations, financial condition and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition, an extended decline in economic conditions could make it more difficult for customers to pay for the utility services they consume, thereby affecting the aging and collection of the utilities' trade receivables.

***Energy conservation, energy efficiency, distributed generation, community choice aggregation and other factors that reduce energy demand could adversely affect the Corporation's business, financial condition and results of operations.***

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of global warming and overall climate change has increased the incentive to increase energy efficiency and reduce energy consumption. In addition, significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may increase as a result of government subsidies, improving economics and changing customer preferences.

Increased adoption of these practices, requirements and technologies could reduce demand for utility-scale electricity generation, which may adversely affect market prices at which the Liberty Power Group can sell wholesale electric power.

Increased adoption of these practices may decrease the pool of customers from whom fixed costs would be recovered. If the Liberty Utilities Group were unable to adjust distribution rates to reflect the reduced energy demand, the Corporation's business, financial condition and results of operations could be adversely affected.

***The Corporation is subject to physical and financial risks associated with global climate change.***

Global climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events including wildfires. Customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, which could adversely affect the Corporation's business, results of operations and cash flows.

***The Corporation and its subsidiaries face a number of environmental risks which have the potential to result in significant environmental liabilities.***

The Corporation and its subsidiaries face a number of environmental risks that are normal aspects of operating within the power generation and utilities business segments, which have the potential to result in harm to the environment, including wildlife, resulting in significant environmental liabilities and reputational impact. Certain environmental risks associated with the Corporation's operations include uncontrolled natural gas or contaminant releases (or releases above the permitted limits), generation of hazardous materials, failure to maintain compliance with obligations under permits and licenses (such as continuous emissions monitoring, periodic reporting/source testing, and general performance/operating conditions), operations adjustments or liability, and related financial impacts, resulting from wildlife mortality, emissions, including noise, and dam safety.

In addition, the Corporation's operating subsidiaries generate certain hazardous wastes, which must be managed in accordance with various federal, state and local environmental laws. Under federal and state 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.

***The Corporation's facilities and operations are exposed to effects of natural disasters and other catastrophic events beyond the Corporation's control and such events could result in a material adverse effect.***

The Corporation's facilities and operations are exposed to potential interruption and damage, and partial or full loss, resulting from environmental disasters (e.g. floods, high winds, fires, ice storms, and earthquakes), other seismic activity, equipment failures and the like. There can be no assurance that in the event of an earthquake, hurricane, tornado, tsunami, typhoon, terrorist attack, act of war or other natural, manmade or technical catastrophe, all or some parts of the Corporation's generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event which disrupts the ability of the Corporation's power generation assets to produce or sell power for an extended period, including events which preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on the Corporation's business. The Corporation's assets could be exposed to effects of severe weather conditions, natural and man-made disasters and potentially other catastrophic events. The occurrence of such an event may not release the Corporation from performing its obligations pursuant to PPAs or other agreements with third parties.

Certain of the Corporation's utilities operate in remote and mountainous terrain, where the Corporation's facilities are at increased risk of loss or damage from fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

***Security breaches, criminal activity, theft, terrorist attacks and other threats or incidents relating to the Corporation's information security could directly or indirectly interfere with the Corporation's operations, could expose the Corporation or its customers or employees to risk of loss, and could expose the Corporation to liability, regulatory penalties, reputational damage and other harm to its business.***

The Corporation relies upon information technology networks, systems and devices to process, transmit and store electronic information, and to manage and support a variety of business processes and activities. The Corporation also uses information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. The Corporation's technology networks, systems and devices collect and store sensitive data, including system operating information, proprietary business information belonging to the Corporation and third parties, as well as personal information belonging to the Corporation's customers and employees.

The Corporation's information systems and information technology networks, devices and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, disruptions during software or hardware upgrades, telecommunication failures, theft, natural disasters or other similar events. In addition, certain sensitive information and data may be stored by the Corporation in physical files and records on its premises or transmitted to the Corporation verbally, subjecting such information and data to a risk of theft and misuse. The occurrence of any of these events could impact the reliability of the Corporation's power generation facilities and utility distribution systems; could expose the Corporation, its customers or its employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against the Corporation, damage the Corporation's reputation or otherwise harm the Corporation's business.

The Corporation cannot accurately assess the probability that a security breach may occur or accurately quantify the potential impact of such an event. The Corporation can provide no assurance that it will identify and remedy all cybersecurity, physical security or system vulnerabilities or that unauthorized access or errors will be identified and remedied.

***The loss of key personnel, the inability to hire and retain qualified employees, and labour disruptions could adversely affect the Corporation's business, financial position and results of operations.***

The Corporation's operations depend on the continued efforts of its employees. Hiring and retaining key employees and maintaining the ability to attract new employees are important to the Corporation's operational and financial performance. The Corporation cannot guarantee that any member of its management or any one of its key employees will continue to serve in any capacity for any particular period of time.

Certain events or conditions, such as an aging workforce, epidemic or pandemic, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges the Corporation might face as a result of such risks include a lack of resources, losses to its knowledge base and the time required to develop new workers' skills. In any such case, costs, including costs for contractors to replace employees, productivity costs and safety costs may rise. If the Corporation is unable to successfully attract and retain an appropriately qualified workforce, its financial position or results of operations could be negatively affected.

The maintenance of a productive and efficient labour environment without disruptions cannot be assured. In the event of a strike, work stoppage or other form of labour disruption, the Corporation would be responsible for procuring replacement labour and could experience disruptions in its operations and incur additional expense.

***The Corporation's revenues and results of operations are affected by seasonal fluctuations and year to year variability in weather conditions and natural resource availability.***

The Corporation is subject to risks associated with seasonal fluctuations and year to year variability in weather conditions and natural resource availability, which affect the quantity of electric power generated and sold by the Liberty Power Group, the availability of water to be distributed by the Liberty Utilities Group and the demand for the utility services of the Liberty Utilities Group.

The Liberty Utilities Group's water distribution operations depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of these utilities.

Demand for water, electricity and natural gas from the Liberty Utilities Group's utility distribution systems is affected by weather conditions and temperature. Demand for water may decrease if there is above normal rainfall or rainfall is more frequent than normal, or if government restrictions are imposed on water usage during drought conditions. Demand for electricity and natural gas are also subject to significant seasonal variation, year-to-year variations and changes in weather patterns.

Please see "Description of the Business – Liberty Power Group – Cycles and Seasonality" and "Description of the Business – Liberty Utilities Group – Cycles and Seasonality" for a detailed description and discussion of these risks.

***The Corporation historically has, and may in the future, enter into long-term PPAs and derivative contracts to reduce the risk of fluctuations in electricity prices, which contracts could give rise to performance and financial risks and could result in significant costs to the Corporation.***

The Liberty Power Group sells a significant portion of the energy (and renewable energy credits) it generates under long-term PPAs. The Liberty Power Group also enters into financial or physical power hedges to reduce the risk from fluctuations in market price. For instance, several of the Liberty Power Group's wind energy production facilities are subject to long-term hourly energy price hedges for a portion of their expected energy production. The Corporation may incur significant costs in establishing or terminating hedging arrangements or may be unable to benefit from favourable changes in market price as a result of these hedges.

In addition, the Corporation may not be able to generate power in the amounts or at the times required by the applicable hedge contract, due to the variable nature of the natural resource (for renewable power generation) or due to transmission grid curtailments, mechanical failures or other reasons. Because of this risk, the Corporation typically does not hedge the full expected production of a particular facility, which leaves a portion of expected production subject to market price risk. In addition, production shortfalls force the Liberty Power Group to purchase power in the merchant market at prevailing rates to settle against the applicable hedge contract. Such factors could materially and adversely affect the Corporation's results of operations and cash flows, depending on both the amount of shortfall and the market price of electricity at the time of the shortfall.

***Changes in technology and regulatory policies may lower the value of electric utility facilities.***

The Corporation primarily generates electricity at large central facilities and delivers that electricity to customers using its transmission and distribution facilities. This method results in economies of scale and generally lower costs than newer technologies, such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. The ability to maintain relatively low-cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers are significant determinants of the Corporation's competitiveness. Further, in the event that alternative generation resources are mandated, subsidized or encouraged through climate legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could displace a higher marginal cost central generating plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region would be able to sell their output and could adversely affect the Corporation's financial condition, results of operations and cash flows, which could also result in an impairment of certain long-lived assets.

***Liberty Power Group's facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets.***

A substantial portion of the Liberty Power Group's power generation facilities depend on electric transmission systems and related facilities owned and operated by third parties to deliver the electricity the Liberty Power Group generates to delivery points where ownership changes and the Corporation is paid. These grids operate with both regulatory and physical constraints which in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which the Liberty Power Group's power generation facilities are physically disconnected from the power grid, or their production curtailed, for short periods of time. Most of the Corporation's electricity sales contracts do not provide for payments to be made if electricity is not delivered.

The power generation facilities of the Liberty Power Group may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which its power generation facilities are connected. In the future, these power generation facilities may not be able to secure access to interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs in attempting to negotiate or renegotiate PPAs or to construct new projects. Any such increased costs and delays could delay the commercial operation dates of Liberty Power Group's new projects and negatively impact the Corporation's revenues and financial condition.

***The Corporation's subsidiaries do not own all of the land on which their projects are located and their use and enjoyment of real property rights for their projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to the Corporation's subsidiaries' projects, which could have a material adverse effect on their business, results of operations, financial condition and cash flows.***

The Corporation's subsidiaries do not own all of the land on which their projects are located. Such projects generally are, and future projects may be, located on land occupied under long-term easements, leases and rights of way. The ownership interests in the land subject to these easements, leases and rights of way may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of the rights under such easements, leases or rights of way held by the Corporation's operating subsidiaries may be subject to the rights of these third parties, and the rights of the Corporation's operating subsidiaries to use the land on which their projects are or will be located and their projects' rights to such easements, leases and rights of way could be lost or curtailed. Any such loss or curtailment of the rights of the Corporation's operating subsidiaries to use the land on which their projects are or will be located could have a material adverse effect on their business, results of operations, financial condition and cash flows.

***The Corporation may experience critical equipment breakdown or failure, which could have a material adverse effect on the Corporation's financial condition, results of operations, liquidity, reputation and ability to make distributions.***

The Corporation's facilities are subject to the risk of critical equipment breakdown or failure and lower-than-expected levels of efficiency or operational performance due to the deterioration of assets from use or age, latent defect and design or operator error, among other things. These and other operating events and conditions could result in service disruptions and, to the extent that a facility's equipment requires longer than forecasted down times for maintenance and repair, or suffers disruptions of power generation, distribution or transmission for other reasons, the Corporation's business, operating results, financial condition or prospects could be adversely affected. In addition, a portion of the Corporation's infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged.

***Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to the business of the Corporation. Continued hostilities or sustained military campaigns may adversely impact our consolidated financial position, results of operations and cash flows.***

The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist attacks on the electric utility and natural gas midstream industry in general, and on the Corporation in particular, cannot be known. Increased security measures taken by the Corporation as a precaution against possible terrorist attacks have resulted in increased costs to the business of the Corporation. Uncertainty surrounding continued hostilities or sustained military campaigns may affect operations of the Corporation in unpredictable ways, including disruptions of supplies and markets for products of the Corporation, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. The Corporation cannot predict the impact that a terrorist attack may have on the energy industry in general.

The Corporation's facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to the Corporation's generation, transmission and distribution systems or to the electrical grid in general, and could result in a decline in the general economy and have a material adverse effect on the Corporation.

***The Corporation's financial performance may be adversely affected by fluctuations in commodity prices.***

Market prices for power, generation capacity, ancillary services and natural gas are unpredictable and tend to fluctuate substantially, which may affect the Corporation's operating results. With respect to the Liberty Utilities Group, commodity price exposure is primarily limited to the cost of electricity and natural gas. Although the Liberty Utilities Group's utility rates and tariffs are generally designed to allow recovery of commodity costs, timing differences and other factors, which may be exacerbated by fluctuating prices, may result in less than full recovery.

***Cash flow deferrals related to energy commodities can be significant.***

The Corporation is permitted to collect from customers only amounts approved by regulatory commissions. However, the Corporation's costs to provide utility services can be much higher or lower than the amounts currently billed to customers. The Corporation is permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates reduce cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect the Corporation's results of operations.

Even if the regulators ultimately allow the Corporation to recover deferred power and natural gas costs, the Corporation's operating cash flows can be negatively affected until these costs are recovered from customers.

***The Liberty Utilities Group is obligated to serve utility customers within its certificated service territories, which may require that the Corporation make capital expenditures and incur indebtedness to expand service to new customers.***

The Liberty Utilities Group may have facilities located within areas 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 Liberty Utilities Group may be required to solicit additional capital or incur additional borrowings to finance these future construction obligations.

***As a holding company, the Corporation does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments.***

The Corporation is a holding company with no significant operations of its own, and the Corporation's primary assets are shares or other ownership interests of its subsidiaries. The Corporation's subsidiaries are separate and distinct legal entities and may have no obligation to pay any amounts to the Corporation, whether through dividends, loans or other means. The ability of the Corporation's subsidiaries to pay dividends or make distributions to the Corporation depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future secured debt and other debt or equity securities. Further, the amount and payment of dividends from any subsidiary is at the discretion of such subsidiary's board of directors, which may reduce or cease payment of dividends at any time. In addition, there may be changes to tax regulation affecting the repatriation of dividends from other countries, which may negatively affect us.

***The Corporation and its subsidiaries are not able to insure against all potential risks and may become subject to higher insurance premiums, and the Corporation's ability to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.***

The Corporation maintains insurance coverage for certain exposures, but this coverage is limited and the Corporation is generally not fully insured against all significant losses. Such insurance may not continue to be offered on an economically feasible basis and may not cover all events that could give rise to a loss or claim involving the Corporation's assets or operations. The Corporation's ability to obtain and maintain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.

If the Corporation were to incur a serious uninsured loss or a loss significantly exceeding the limits of their insurance policies, the results could have a material adverse effect on the Corporation's business, results of operations, financial condition and cash flows. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the Liberty Utilities Group, the Corporation may make an application to an applicable regulatory authority for the recovery of these costs through customer rates to offset any loss. However, the Corporation cannot provide assurance that the regulatory authorities would approve any such application in whole or in part. This potential recovery mechanism is not available to Liberty Power Group.

## 4.2 Risk Factors Relating to Financing and Financial Reporting

***A downgrade in the Corporation's credit ratings or the credit ratings of its subsidiaries could have a material adverse effect on the Corporation's business, cost of capital, financial condition and results of operations.***

APUC has a long-term consolidated corporate credit rating of BBB from S&P and BBB from DBRS and BBB from Fitch. The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by such entities. See "*Description of the Business – Credit Ratings*".

There can be no assurance that any of the current ratings of the Corporation 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. A downgrade in credit ratings would result in an increase in the Corporation's borrowing costs under its bank credit facilities and future issuances of long-term debt securities. Any such downgrade could also adversely impact the market price of the outstanding securities of the Corporation. If any of these ratings fall below investment grade (defined as BBB- or above for S&P and Fitch, BBB (low) or above for DBRS and Baa3 or above for Moody's), the Corporation's ability to issue short-term debt or other securities, or to market those securities, may be impaired or become more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on the Corporation's business, cost of capital, financial condition and results of operations.

***Financial market disruptions or other factors could increase financing costs or limit access to credit and capital markets, which could adversely affect the Corporation's ability to refinance existing indebtedness on favourable terms, execute its acquisition and investment strategy, and finance its other activities upon favourable terms.***

As of December 31, 2018, the Corporation had substantial indebtedness. Management of the Corporation believes, based on its current expectations as to the Corporation's future performance, that the cash flow from operations, the funds available under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, the Corporation's expected revenue and capital expenditures are only estimates. Moreover, actual cash flows from operations will depend on regulatory, market and other conditions that are beyond the Corporation's control. As a result, there can be no assurance that management's expectations as to future performance will be realized.

The Corporation's ability to raise additional debt or equity, on favourable terms or at all, may be adversely affected by any adverse financial and operational performance or by financial market disruptions or other factors outside the Corporation's control.

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

The Corporation will need to refinance its existing consolidated indebtedness over time. There can be no assurance that the Corporation will be successful in refinancing its indebtedness when necessary or that additional financing will be obtained when needed, on commercially reasonable terms or at all. In the event that the Corporation cannot refinance indebtedness or raise additional indebtedness, or if the Corporation cannot refinance its indebtedness or raise additional indebtedness on terms that are not less favourable than the current terms, the Corporation's cash flows and ability to declare dividends may be adversely affected.

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

***Sustained increases in interest rates could negatively affect the Corporation's financing costs, ability to access capital and ability to continue successfully implementing its business strategy.***

The Corporation is exposed to interest rate risk from certain outstanding variable interest indebtedness. As a result, increases in interest rates could materially increase the Corporation's financing costs and adversely affect its results of operations, cash flows, borrowing capacity and ability to implement its business strategy.

***Currency exchange rate fluctuations may affect the Corporation's financial results and increase certain financing risks.***

Currency fluctuations may affect the cash flows the Corporation realizes from its consolidated operations because a significant portion of the Corporation's revenues are generated in U.S. dollars. Although the Corporation may enter into derivative contracts to hedge currency exchange rate exposure, the Corporation typically does not hedge its full exposure. If the Corporation does enter into currency hedges and exchange rates move in a favourable direction, such currency hedges may reduce or eliminate the Corporation's realization of the benefit of favourable exchange rate movement. In addition, currency hedging transactions will be subject to risks that the applicable counterparty may prove unable or unwilling to perform their obligations under the contracts, as a result of which the Corporation would lose some or all of the anticipated benefits of such hedging transactions.

***The Corporation is, and will continue to be, party to agreements, including credit agreements and indentures, that contain covenants that restrict its financial flexibility.***

The Corporation's existing credit facilities contain covenants imposing certain requirements on the Corporation's business including covenants regarding the ratio of indebtedness to total capitalization. Furthermore, APUC and its subsidiaries have, and may continue to, periodically issue long-term debt, which may consist of both secured and unsecured indebtedness. These third-party debt agreements also contain covenants, including covenants regarding the ratio of indebtedness to total capitalization. These requirements may limit the Corporation's ability to take advantage of potential business opportunities as they arise and may adversely affect the Corporation's conduct and the current business of certain operating subsidiaries, including restricting the ability to finance future operations and capital needs and limiting the subsidiaries' ability to engage in other business activities. Other covenants place or could place restrictions on the Corporation's ability and the ability of its operating subsidiaries to, among other things, incur additional debt, create liens, and sell or transfer assets.

Agreements the Corporation enters into in the future may also have similar or more restrictive covenants, especially if the general credit market deteriorates. A breach of any covenant in the existing credit facilities or the agreements governing the Corporation's other indebtedness would result in an event of default. Certain events of default may trigger automatic acceleration of payment of the underlying obligations or may trigger acceleration of payment if not remedied within a specified period. Events of default under one agreement may trigger events of default under other agreements, although the Corporation's regulated utilities are not subject to the risk of default of affiliates. Should payments become accelerated as the result of an event of default, the principal and interest on such borrowing would become due and payable immediately. If that should occur, the Corporation may not be able to make all of the required payments or borrow sufficient funds to refinance the accelerated debt obligations. Even if new financing is then available, it may not be on terms that are acceptable to the Corporation.

***A significant portion of the Corporation's debt will mature over the next five years and will need to be paid or refinanced, and changes to the debt and equity markets could adversely affect the Corporation's business.***

A significant portion of the Corporation's debt is set to mature in the next five years, including its revolving credit facility. The Corporation may not be able to refinance its maturing debt on commercially reasonable terms, or at all, depending on numerous factors, including its financial condition and prospects at the time and the then current state of the banking and capital markets in Canada and the United States.

***Challenges to the Corporation's tax positions, and changes in applicable tax laws, could materially and adversely affect returns to the Corporation's shareholders.***

The Corporation is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which we do business could adversely affect the Corporation's results from operations, returns to shareholders and cash flow.

The Corporation cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Corporation, including with respect to claimed expenses and the cost amount of the Corporation's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect the results of operations and financial position of the Corporation.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or we are unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that we are committed to complete. In addition, the Liberty Power Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Corporation. The U.S. Department of Treasury has released proposed regulations related to business interest expense limitations, Base Erosion Anti-Abuse Tax, and anti-hybrid structures as part of the implementation of U.S. tax reform. These proposed regulations are not final and are subject to change in the regulatory review process which is expected to be completed later in 2019. The timing or impacts of any future changes in tax laws, including the impacts of proposed regulations, cannot be predicted. As a result, there may be future impacts on the results of operations, financial condition and cash flows of the Corporation.

***The Corporation is subject to funding risks associated with defined benefit pension and OPEB plans.***

Certain utility businesses acquired by the Corporation maintain defined benefit pension plans covering substantially all of the employees of the acquired business, and other post-employment benefit ("**OPEB**") plans for eligible retired employees, including retiree health care and life insurance benefits. The Corporation 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.

Future contributions to the Corporation's plans are impacted by a number of variables, including the investment performance of the plans' assets and the discount rate used to value the liabilities of the plans. If capital market returns are below assumed levels, or if discount rates decrease, the Corporation could be required to make contributions to its plans in excess of those currently expected, which would adversely affect the Corporation's cash flows.

***The Corporation is subject to credit risk of customers and other counterparties.***

The Corporation is subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Corporation, including paying amounts that they owe to the Corporation. This credit risk exists with respect to utility customers, as well as counterparties to long-term PPAs, supply agreements and derivative financial instruments, among others.

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

***The Corporation makes certain assumptions, judgments and estimates that affect amounts reported in its consolidated financial statements, which, if not accurate, may adversely affect its financial results.***

APUC prepares its consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management judgment include the scope of consolidated entities, useful lives and recoverability of depreciable assets, the measurement of deferred taxes and the recoverability of deferred tax assets, rate-regulation, unbilled revenue, asset retirement obligations, 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 and any inaccuracies in these estimates could result in the Corporation incurring significant expenses and adversely affect the Corporation's financial results.

## 4.3 Risk Factors Relating to Regulatory Environment

***The profitability of the Corporation's businesses depends in part on regulatory climates in the jurisdictions in which it operates, and the failure to maintain required regulatory authorizations could materially and adversely affect the Corporation.***

The utility commissions in the jurisdictions in which the Liberty Utilities Group operates regulate many aspects of its utility operations, including the rates that the Liberty Utilities Group can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and the utility's ability to recover the costs that it incurs, including capital expenditures and fuel and purchased power costs. In addition, the electrical transmission system owned by the Liberty Power Group, which is used to connect the Tinker Hydro Facility to the New Brunswick transmission network, is also subject to regulation by the New Brunswick Energy and Utilities Board.

A fundamental risk faced by any regulated utility is the disallowance by the utility's regulator of costs requested to be placed into the utility's revenue requirement. In addition, the time between the incurrence of costs and the granting of the rates to recover those costs by state or provincial regulatory agencies – known as "regulatory lag" – can adversely affect profitability. If the Corporation is unable to recover increased costs of operations or its investments in new facilities, or in the event of significant regulatory lag, the Corporation's results of operations could be adversely affected.

In addition, there is a risk that the utility's regulator will not approve the transmission and distribution revenue requirements requested in outstanding or future applications for rates or will, on its own initiative, seek to reduce the existing revenue requirements. Rate applications for revenue requirements are subject to the utility regulator's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the utility regulators will permit the Corporation to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular return on equity. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Liberty Utilities Group's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Corporation. In addition, there is no assurance that the Corporation will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

In the case of some of the Corporation's hydroelectric generating facilities, water rights are owned by governments that reserve the right to control water levels, which may affect revenue, while in the United States, hydroelectric generating facilities are required to be licensed or have valid exemptions from FERC. The failure to obtain all necessary licenses or permits for such facilities, including renewals thereof or modifications thereto, may result in an inability to operate the facility and could adversely affect cash generated from operating activities.

FERC has jurisdiction over wholesale rates for all electric energy sold by the Liberty Power Group in the United States. The Liberty Power Group's facilities in the United States are required to meet the requirements of a "qualifying facility" or an "exempt wholesale generator" and, subject to certain exceptions, to obtain and maintain authority from FERC to sell power at market-based rates. The failure of the Liberty Power Group to maintain market-based rate authorization for certain facilities that currently have it would constitute a default under the facility's PPA and any project financing for such facility and could materially and adversely affect the Corporation.

The operations of each of the Corporation's business units are also subject to a variety of federal, provincial and state environmental and other regulatory bodies, the requirements and regulations of which affect the operations of, and costs incurred by, the Corporation. In addition, changes in regulations or the imposition of additional regulations also could have a material adverse effect on the Corporation's results of operations.

***The Corporation's operations are subject to numerous health and safety laws and regulations.***

The operation of the Corporation's facilities requires adherence to safety standards imposed by regulatory bodies. These laws and regulations require the Corporation to obtain approvals and maintain permits, undergo environmental impact assessments and review processes and implement environmental, health and safety programs and procedures to control risks associated with the siting, construction, operation and decommissioning of energy projects. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and administrative sanctions.

Health and safety laws, regulations and permit requirements may change or become more stringent. Any such changes could require the Corporation to incur materially higher costs than the Corporation has incurred to date. The Corporation's costs of complying with current and future health and safety laws, regulations and permit requirements, and any liabilities, fines or other sanctions resulting from violations of them, could adversely affect its business, financial condition and results of operations.

***The Corporation is subject to numerous environmental laws, regulations and other standards that may result in capital expenditures, increased operating costs and various liabilities.***

The Corporation is subject to extensive federal, state, provincial and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on the Corporation's results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted, which may substantially increase the Corporation's future environmental expenditures. Although the Liberty Utilities Group has historically recovered such costs through regulated customer rates, there can be no assurance that the Liberty Utilities Group will recover all or any part of such increased costs in future rate cases. The Liberty Power Group generally has no right to recover such costs from customers. The incurrence of additional material environmental costs which are not recovered in utility rates may have a material adverse effect on the Corporation's business, financial condition and results of operations.

***The Corporation may pursue growth opportunities in new markets that are subject to foreign laws and regulations that are more onerous than the laws and regulations to which it is currently subject.***

The Corporation may pursue growth opportunities in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide the same type of legal certainty and rights, in connection with the Corporation's contractual relationships in such countries, as are afforded to the Corporation in Canada and the U.S., which may adversely affect the Corporation's ability to receive revenues or enforce its rights in connection with any operations in such jurisdictions. In addition, the laws and regulations of some countries may limit the Corporation's ability to hold a majority interest in certain projects, thus limiting the Corporation's ability to control the operations of such projects. Any existing or new operations or interests of the Corporation may also be subject to significant political, economic and financial risks, which vary by country, and may include: (i) changes in government policies or personnel; (ii) changes in general economic conditions; (iii) restrictions on currency transfer or convertibility; (iv) changes in labour relations; (v) political instability and civil unrest; (vi) regulatory or other changes adversely affecting the local utility market; and (vii) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

## 4.4 Risk Factors Relating to Strategic Planning and Execution

***The Corporation is subject to risks associated with its growth strategy that may adversely affect its business, results of operations, financial condition and cash flows, and actual capital expenditures may be lower than planned.***

The Corporation has a history of growth through acquisitions and organic growth from capital expenditures in existing service territories. There is no certainty that the Corporation will be successful in pursuing this growth strategy in the future. There can be no assurance that the Corporation will be able to identify attractive acquisition or development candidates in the future or that it will be able to realize growth opportunities that increase the amount of cash available for distribution. The Corporation may also face significant competition for growth opportunities and, to the extent that any opportunities are identified, may be unable to effect such growth opportunities due to a lack of necessary capital resources. Risks related to capital projects include schedule delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulators, however, there is no assurance that any project cost overruns would be approved for recovery in customer rates.

Any growth opportunity could involve potential risks, including an increase in indebtedness, the potential disruption to the Corporation's ongoing business, the diversion of management's attention from other business concerns and the possibility that the Corporation will incur more costs than originally anticipated or, in the case of acquisitions, more than the acquired company or interest is worth. In addition, funding requirements associated with the growth opportunity, including any acquisition, development or integration costs, may reduce the funds available to pay dividends.

The Liberty Utilities Group's capital expenditure program and associated rate base growth are key assumptions in the Corporation's targeted dividend growth guidance. Actual capital expenditures may be lower than planned due to factors beyond the Corporation's control, which would result in a lower than anticipated rate base and have an adverse effect on the Corporation's results of operations, financial condition and cash flows. This could limit the Corporation's ability to meet its targeted dividend growth.

***The Corporation's development and construction activities are subject to material risks, including expenditures for projects that may prove not to be viable, construction cost overruns and delays, inaccurate estimates of expected energy output or other factors, and failure to satisfy tax incentive requirements or to meet third-party financing requirements.***

The Corporation actively engages in the development and construction of new power generation facilities, and currently has a pipeline of projects in development or construction, consisting mainly of solar and wind power generation projects, as well as the development and construction of transmission and distribution assets. In addition, each of the Corporation's business segments may occasionally undertake construction activities as part of normal course maintenance activities.

Significant costs must be incurred to determine the technical feasibility of a project, obtain necessary regulatory approvals and permits, obtain site control and interconnection rights and negotiate revenue contracts for the facility before the viability of the project can be determined. 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, or the failure of a project to proceed and the resultant loss of amounts invested or expenses already incurred.

Material delays or cost overruns could be incurred by the Corporation and its development and construction projects as a result of vendor or contractor non-performance, technical issues with the interconnection utility, disputes with landowners or other parties, severe weather and other causes.

The Corporation's assessment of the feasibility, revenues and profitability of a renewable power generation facility depends upon estimates regarding the strength and consistency of the applicable natural resource (such as wind, solar radiance or hydrology) and other factors, such as assessments of the facility's potential impact on wildlife. If weather patterns change or actual data proves to be materially different than estimates, the amount of electricity to be generated by the facility and resulting revenues and profitability may differ significantly from expected amounts.

For certain of its development projects, the Liberty Power Group relies on financing from third party tax equity investors, the participation of which depends upon qualification of the project for U.S. tax incentives and satisfaction of the investors' investment criteria. 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 adversely impacted.

The Corporation's construction activities relating to its utility and power generation projects utilize a variety of products and materials. The cost to the Corporation of such products and materials may be impacted by a number of factors beyond the Corporation's control, including their general availability and the impact of tariffs and duties imposed by various governmental authorities. While the Liberty Utilities Group may be able to recover any such increased costs in future rate cases, there is generally no such recovery mechanism available to the Liberty Power Group for such costs. The financial condition and results of operations of the Corporation may be impacted as a result.

Energy generated by the Corporation is often sold under long-term PPAs. PPAs generally contain customary terms including: the amount paid for energy from the project over the term of the agreement (which rate can be materially higher than prevailing market rates) and a requirement for the project to comply with technical standards and to achieve commercial operation within time frames prescribed by the contract. A failure to achieve satisfactory construction progress and/or the occurrence of any permitting or other unanticipated delays at a project could result in a failure to comply with the applicable PPA requirements within the specified time frames. Remedies for failure to comply with material provisions of a PPA generally include, among other things, the potential termination of the agreement by the non-defaulting party. Any such termination could have a material adverse effect on the Corporation's results of operations and financial position.

***The Liberty Power Group depends on certain key customers for a significant portion of its revenues. The loss of any key customer or the failure to secure new PPAs or to renew existing PPAs could increase market price risk with respect to the sale of generated energy and renewable energy credits.***

A substantial portion of the output of the Liberty Power Group's power generation facilities is sold under long-term PPAs, under which a single purchaser is obligated to purchase all of the output of the applicable facility and (in most cases) associated renewable energy credits. The termination or expiry of any such PPA, unless replaced or renewed on equally favourable terms, would adversely affect the Corporation's results of operations and cash flows and increase the Corporation's exposure to risks of price fluctuations in the wholesale power market.

Securing new PPAs is a risk factor in light of the competitive environment in which the Corporation operates. The Corporation expects the Liberty Power Group to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive requests for proposals processes. During these processes, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There can be no assurance that the Corporation will be selected as power supplier following any particular request for proposals in the future or that existing PPAs will be renewed or will be renewed on favourable terms and conditions upon the expiry of their respective terms.

***The Corporation may fail to complete planned acquisitions, which may result in a loss of expected benefits from such acquisitions or may generate significant liabilities.***

Acquisitions of businesses and technologies are a part of the Corporation's overall business strategy. Because of the regulated nature of certain of the business sectors in which the Corporation operates, certain acquisitions by the Corporation, including the EGNB Acquisition, the acquisition of SLG and the acquisition of ATN3, are subject to various regulatory approvals and, consequently, to the risks that such approvals may not be timely obtained or may impose unfavourable conditions that could impair the ability to complete the acquisition or impose adverse conditions on the Corporation following the acquisition.

In addition, the Corporation may enter into acquisition agreements under which the Corporation's obligations are not contingent upon availability of financing, in which case the Corporation could incur higher than expected financing costs or, if such financing cannot be obtained, significant liability to the seller.

Failure to complete an acquisition may decrease investor confidence. In addition, the terms of an acquisition agreement may impose liability on the Corporation for failing to complete the acquisition, which in some cases may include liability where the reasons for failure to complete the acquisition are not entirely within the Corporation's control.

***The Corporation may fail to realize the intended benefits of completed acquisitions or may incur unexpected costs or liabilities as a result of completed acquisitions.***

The Corporation may not effectively integrate the services, technologies, key personnel or businesses of acquired companies or may not obtain anticipated operating benefits or synergies from completed transactions. In addition, the Corporation may incur unexpected costs or liabilities in connection with the closing or integration of any acquisition.

The success of an acquisition may depend on retention of the workforce or key employees of the acquired business. The Corporation may not be successful in retaining such workforce or key employees or in retaining them at anticipated costs.

In addition, the Corporation may be subject to unexpected liabilities, despite any due diligence investigation of an acquired business or any contractual remedies the Corporation may have against the sellers. Detailed information regarding an acquired business is generally available only from the seller, and contractual remedies are typically subject to negotiated limitations. In addition, in cases in which the target company is publicly traded and its shares are widely held, the Corporation is likely not to have recourse following the completion of the acquisition for misrepresentations made to the Corporation in connection with the acquisition.

***The Corporation's investment in Atlantica is subject to risks, including that the market price of Atlantica's securities could decline or Atlantica may make decisions with which the Corporation does not agree or take risks or otherwise act in a manner that does not serve the Corporation's interests.***

The Corporation owns an equity interest in Atlantica of approximately 41.5%. This investment is subject to a risk that Atlantica may make business, financial or management decisions with which the Corporation does not agree, or that Atlantica's other stockholders or management of Atlantica may take risks or otherwise act in a manner that does not serve the Corporation's interests. If any of the foregoing were to occur, the value of the Corporation's investment could decrease and the Corporation's financial condition, results of operations and cash flow could be adversely affected.

Dividends declared and paid by Atlantica are made at the discretion of Atlantica's board of directors. The Corporation does not control the board of directors of Atlantica. Therefore, there can be no assurance that dividends will continue to be paid on Atlantica's ordinary shares, will continue to be paid at the same rate as they are currently being paid or will be paid at any specified target rate.

Demand in the capital markets for Atlantica's ordinary shares can vary over time for numerous reasons outside of the Corporation's control, including performance of the Atlantica business and changes in the prospects of Atlantica. Consequently, it may be difficult for the Corporation to dispose of its anticipated interest in Atlantica at favourable times or prices.

***The Corporation's investment in Atlantica and its international acquisition, development, construction and operating activities, including through AAGES, expose the Corporation to certain risks that are particular to certain international markets.***

Atlantica owns, manages and acquires renewable energy, conventional power, electric transmission lines and water assets in certain jurisdictions where the Corporation may not operate. The Corporation, through its investment in Atlantica, is indirectly exposed to certain risks that are particular to the markets in which it operates, including, but not limited to, risks related to: conditions in the global economy; changes to national and international laws, political, social and macroeconomic risks relating to the jurisdictions in which Atlantica operates, including in emerging markets, which could be subject to economic, social and political uncertainties; anti-bribery and anti-corruption laws and substantial penalties and reputational damage from any non-compliance therewith; significant currency exchange rate fluctuations; Atlantica's ability to identify and/or consummate future acquisitions on favourable terms or at all; Atlantica's inability to replace, on similar or commercially favourable terms, expiring or terminated offtake agreements; termination or revocation of Atlantica's concession agreements or PPAs; and various other factors. These risks could affect the profitability and growth of Atlantica's business, and ultimately the profitability of the Corporation's anticipated investment therein.

The Corporation's international acquisition, development, construction and operating activities, including through the AAGES joint venture, expose the Corporation to similar risks and could likewise affect the profitability, financial condition and growth of the Corporation.

***The Liberty Utilities Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions.***

The Liberty Utilities Group's water, wastewater, electricity and natural gas 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 that just and fair compensation be paid to the Liberty Utilities Group, and the Liberty Utilities Group believes that such compensation generally would reflect fair market value for any assets that are taken. However, the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and, therefore, there can be no assurance that the value received for those assets would reflect the value the Corporation attributes to such assets, that the value received would be above book value or that the Corporation would not recognize a loss.

***Increased external stakeholder activism could have an adverse effect on the Corporation's business, operations or financial condition.***

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility return on equity and executive compensation. In addition, public opposition to larger infrastructure projects and renewable energy projects in certain areas is becoming increasingly common, which may impact the Corporation's capital programs, development activities and operations. The social acceptance by external stakeholders, including, in some cases, First Nations and other aboriginal peoples, local communities, landowners and other interest groups, may be critical to the Corporation's ability to find and develop new sites suitable for viable renewable energy projects. Failure to obtain proper social acceptance for a project may prevent the development and construction of a project and lead to the loss of all investments made in the development and the write-off of such prospective project. Failure to effectively respond to public opposition may adversely affect the Corporation's capital expenditure programs, and, therefore, future organic growth, which could adversely affect its results of operations, financial condition and cash flows.

***The Corporation may not have sole control over the projects that it invests in with its partners, including Abengoa, or over the revenues and certain decisions associated with those projects, which may limit the Corporation's flexibility and financial returns with respect to these projects.***

The Corporation has, and will in the future continue to have, an equity interest of 50% or less in certain projects. As a result, the Corporation will not control such projects and may be subject to the decision-making of third parties, whose interests may not always be aligned with those of the Corporation. This may limit the Corporation's flexibility and financial returns with respect to these projects.

Despite having a 50% equity stake in AAGES, the joint venture involves risks, including, among others, a risk that Abengoa:

- may have economic or business interests or goals that are inconsistent with the Corporation's economic or business interests or goals;
- may take actions contrary to the Corporation's policies or objectives with respect to the Corporation's investments;
- may contravene applicable anti-bribery laws that carry substantial penalties for non-compliance and could cause reputational damage and a material adverse effect on the business, financial position and results of operations of AAGES and the Corporation;
- may have to give its consent with respect to certain major decisions;
- may become bankrupt, limiting its ability to meet calls for capital contributions and potentially making it more difficult to refinance or sell projects;
- may become engaged in a dispute with the Corporation that might affect the Corporation's ability to develop a project; or
- may have competing interests in the Corporation's markets that could create conflict of interest issues.

Further, the Corporation will not have sole control of certain major decisions relating to the projects that the Corporation owns or pursues through AAGES, including, among others, decisions relating to funding and transactions with affiliates. The Corporation's involvement with AAGES may also present a reputational risk, including from the reputation of Abengoa.

AAGES has obtained the AAGES Secured Credit Facility, which is collateralized through a pledge of the Atlantica ordinary shares held by AY Holdings. A collateral shortfall would occur if the net obligation (as defined in the credit agreement) would equal or exceed 50% of the market value of the Atlantica shares. In the event of a collateral shortfall, AAGES is required to post additional collateral in cash to reduce the net obligation to 40% of the total collateral provided (the "**Collateral Reset Level**"). If AAGES were unable to fund the collateral shortfall, the AAGES Secured Credit Facility lenders hold the right to sell Atlantica shares to reduce the facility to the Collateral Reset Level. The AAGES Secured Credit Facility is repayable on demand if Atlantica ceases to be a public company. If AAGES were unable to repay the amounts owed, the lenders would have the right realize on their collateral.

***The Corporation may sell businesses or assets, which may be sold at a loss and which, regardless of the sales price, may reduce total revenues and net income.***

The Corporation may from time to time dispose of businesses or assets that the Corporation no longer views as being strategic to the Corporation's continuing operations. Such disposals may result in recognition of a loss upon such a sale. In addition, as a result of divestitures, the Corporation's revenues and net income may decrease.

***The price of the Common Shares may be volatile and the value of shareholders' investments could decline.***

The trading price and value of, and demand for, the Common Shares may fluctuate and depend on a number of factors, including:

- the risk factors described in this AIF;
- general economic conditions internationally and within Canada and the United States, including changes in interest rates;
- changes in electricity and natural gas prices;
- actual or anticipated fluctuations in the Corporation's quarterly and annual results and those of the Corporation's competitors;
- the Corporation's reputation, businesses, operations, results and prospects;
- the timing and amount of dividends, if any, declared on the Common Shares;
- future issuances of Common Shares or other securities by the Corporation;
- future mergers and strategic alliances;
- market conditions in the energy industry;
- changes in government regulation, taxes, legal proceedings or other developments;
- shortfalls in the Corporation's operating results from levels forecasted by securities analysts;
- investor sentiment toward the stock of energy companies in general;
- announcements concerning the Corporation or its competitors;
- maintenance of acceptable credit ratings or credit quality; and
- the general state of the securities markets.

These and other factors may impair the development or sustainability of a liquid market for the Common Shares and the ability of investors to sell Common Shares at an attractive price. These factors also could cause the market price and demand for the Common Shares to fluctuate substantially, which may adversely affect the price and liquidity of the Common Shares. These fluctuations could cause shareholders to lose all or part of their investment in Common Shares. Many of these factors and conditions are beyond the Corporation's control and may not be related to its operating performance.

# 5. DIVIDENDS

## 5.1 Common Shares

The amount of dividends declared for each Common Share for fiscal 2016, 2017 and 2018 were $0.41, $0.47 and $0.50, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. APUC's current quarterly dividend to shareholders is $0.1282 per Common Share or $0.5128 per Common Share per annum.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time at its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors previously noted, and there is no assurance as to the amount or timing of such dividends in the future. See "Enterprise Risk Factors".

## 5.2 Preferred Shares

On November 9, 2012, APUC issued 4,800,000 cumulative rate reset Series A preferred shares (the " **Series A Shares**"). Holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year. In each of 2016, 2017 and 2018, dividends were paid at an annual rate equal to C$1.1250 per Series A Share. For the current five-year period from December 31, 2018 to December 31, 2023, the annual rate is equal to C$1.2905 per Series A Share.

On January 1, 2013, the Corporation issued 100 Series C preferred shares (the " **Series C Shares**") and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by certain members of APUC's senior management. The Series C Shares provide dividends essentially identical to those expected from the Class B units. In 2016, 2017 and 2018, dividends paid to holders of Series C Shares were C$10,389, C$8,866 and C$9,653, respectively, per Series C Share.

On March 5, 2014, APUC issued 4,000,000 cumulative rate reset Series D preferred shares (the " **Series D Shares**"). For an initial five-year period, the holders of Series D Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to C$1.250 per Series D Share. In 2016, 2017 and 2018, dividends of C$1.250 per Series D Share were paid.

## 5.3 Dividend Reinvestment Plan

Under APUC's shareholder dividend reinvestment plan (the "**Reinvestment Plan**"), holders of Common Shares who reside in Canada or the United States may opt to reinvest the cash dividends paid on their Common Shares in additional Common Shares which, at APUC's election, will either be purchased on the open market or newly issued from treasury. Common Shares purchased under the Reinvestment Plan are currently being issued from treasury at a 5% discount to the prevailing market price (as determined in accordance with the terms of the Reinvestment Plan). The 5% discount will remain in effect for all cash dividends that may be declared, if any, by the Board until otherwise announced, at its discretion.

# 6. DESCRIPTION OF CAPITAL STRUCTURE

## 6.1 Common Shares

The Common Shares are publicly traded on the TSX and the NYSE under the ticker symbol "AQN". As at December 31, 2018, APUC had 488,851,433 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.

## 6.2 Preferred Shares

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, 2018, APUC had outstanding:

- 4,800,000 Series A Shares, yielding 5.162% annually for the five-year period ending on December 31, 2023;
- 100 Series C Shares; and
- 4,000,000 Series D Shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.

As at December 31, 2018, no Series B Shares, Series E Shares or Series F Shares were outstanding.

**Series A Shares**

The Series A Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on December 31, 2023 and every five years thereafter and are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series B (the "**Series B Shares**"). The Series A Shares were redeemable by APUC on December 31, 2018 (the "**Series A Shares Redemption Right**"), but APUC elected not to exercise its redemption right. The Series A Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series A Shares are entitled to receive C$25.00 per Series A Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

**Series B Shares**

APUC is authorized to issue up to 4,800,000 Series B Shares upon the conversion of Series A Shares upon the occurrence of certain events. The Series B Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on any Series B Conversion Date (as defined in the articles of APUC), and are convertible into Series A Shares upon the occurrence of certain events. The Series B Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series B Shares are entitled to receive C$25.00 per Series B Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC. Upon APUC's election not to exercise the Series A Shares Redemption Right, the holders of the Series A Shares had the right to convert all or part of their Series A Shares into Series B Shares on December 31, 2018. However, since less than the required minimum of 1,000,000 Series A Shares were tendered for conversion, none of the Class A Shares were converted into Class B Shares and no Class B Shares have been issued by APUC.

**Series C Shares**

The Series C Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends and are entitled to cumulative dividends in accordance with the formula set forth in the articles of APUC. The Series C Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series C Shares are entitled to receive the redemption price calculated in accordance with the share terms plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC. The Series C Shares are redeemable upon the occurrence of certain events. During the period between May 20, 2031 and June 19, 2031, the Series C Shares are convertible into Common Shares and, if not so converted, will be automatically redeemed on June 19, 2031. Holders of the Series C Shares include a partnership controlled by Ian Robertson, Chief Executive Officer of the Corporation and a partnership controlled by Chris Jarratt, Vice Chair of the Corporation.

**Series D Shares**

The Series D Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on March 31, 2019 and every five years thereafter, and are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series E (the "**Series E Shares**"). The Series D Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series D Shares are entitled to receive C$25.00 per Series D Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

**Series E Shares**

APUC is authorized to issue up to 4,000,000 Series E Shares upon the conversion of Series D Shares upon the occurrence of certain events. The Series E Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on any Series E Conversion Date (as defined in the articles of APUC), and are convertible into Series D Shares upon the occurrence of certain events. The Series E Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series E Shares are entitled to receive C$25.00 per Series E Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

**Series F Shares**

APUC is authorized to issue an unlimited number of Series F Shares following the conversion of the Subordinated Notes upon the occurrence of certain bankruptcy-related events. The Series F Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends and may be redeemed by APUC, subject to certain restrictions, at any time after October 17, 2023. The Series F Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series F Shares are entitled to receive C$25.00 per Series F Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Subject to applicable corporate law, the outstanding preferred shares are non-voting and not entitled to receive notice of any meeting of shareholders, except that the Series A Shares and Series D Shares (and the Series B Shares and Series E Shares, respectively, into which they are convertible) will be entitled to one vote per share if APUC shall have failed to pay eight quarterly dividends on such shares. The outstanding preferred shares do not have a right to participate in a take-over bid of the Common Shares.

## 6.3 Subordinated Notes

On October 17, 2018, APUC completed the sale of $287.5 million aggregate principal amount of Subordinated Notes. The Subordinated Notes are publicly traded on the NYSE under the ticker symbol “AQNA”.

The Corporation will pay interest on the Subordinated Notes at a fixed rate of 6.875% per year in equal quarterly installments until October 17, 2023. Starting on October 17, 2023, and quarterly on every January 17, April 17, July 17 and October 17 of each year during which the Subordinated Notes are outstanding thereafter until October 17, 2078 (each such date, an “**Interest Reset Date”**), the interest rate on the Subordinated Notes will be reset to an interest rate per annum equal to (i) starting on October 17, 2023, on every Interest Reset Date until October 17, 2028, the three month LIBOR plus 3.677%, payable in arrears, (ii) starting on October 17, 2028, on every Interest Reset Date until October 17, 2043, the three month LIBOR plus 3.927%, payable in arrears, and (iii) starting on October 17, 2043, on every Interest Reset Date until October 17, 2078, the three month LIBOR plus 4.677%, payable in arrears. So long as no event of default has occurred and is continuing, APUC may elect to defer the interest payable on the Subordinated Notes on one or more occasions for up to five consecutive years.

The Subordinated Notes have a maturity date of October 17, 2078. On or after October 17, 2023, APUC may, at its option, redeem the Subordinated Notes at a redemption price equal to 100% of the principal amount thereof, together with accrued and unpaid interest.

Upon the occurrence of certain bankruptcy-related events in respect of APUC, the Subordinated Notes automatically convert into Series F Shares.

## 6.4 Shareholders’ Rights Plan

The shareholders’ rights plan, as amended and restated in 2016 (the “ **Amended and Restated Rights Plan**”) is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value.

Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it (subject to certain exceptions), acquires or announces its intention to acquire 20% or more of the outstanding Common Shares without complying with the permitted bid provisions of the Amended and Restated Rights Plan. Should a non-permitted bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a 50% discount to the market price at the time.

It is not the intention of the Amended and Restated Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Amended and Restated Rights Plan, a permitted bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 105 days. If at the end of 105 days at least 50% of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further 10 days to allow all other shareholders to tender.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2019 (unless extended by approval of the shareholders at such meeting) or its termination under the terms of the Amended and Restated Rights Plan.

# 7. MARKET FOR SECURITIES

## 7.1 Trading Price and Volume

### 7.1.1 Common Shares

The Common Shares are listed and posted for trading on the TSX and NYSE under the symbol "AQN". The following table sets forth the high and low trading prices and the aggregate volumes of trading of the Common Shares for the periods indicated (as quoted by the TSX and NYSE).

| | TSX | | | NYSE | | |
|---|---|---|---|---|---|---|
| **2018** | **High (C$)** | **Low (C$)** | **Volume** | **High ($)** | **Low ($)** | **Volume** |
| January | 14.04 | 13.12 | 22,798,041 | 11.16 | 10.49 | 579,328 |
| February | 13.35 | 12.52 | 25,745,491 | 10.85 | 9.86 | 506,023 |
| March | 13.20 | 12.51 | 29,918,457 | 10.32 | 9.67 | 2,991,068 |
| April | 12.89 | 12.18 | 17,800,921 | 10.12 | 9.59 | 868,146 |
| May | 12.99 | 12.25 | 24,289,158 | 10.18 | 9.54 | 609,806 |
| June | 12.95 | 12.32 | 28,731,693 | 9.87 | 9.48 | 854,873 |
| July | 13.17 | 12.45 | 16,300,248 | 9.92 | 9.45 | 669,612 |
| August | 13.64 | 12.66 | 19,158,974 | 10.45 | 9.74 | 542,652 |
| September | 13.94 | 13.30 | 18,268,777 | 10.71 | 10.11 | 983,847 |
| October | 13.46 | 12.57 | 22,159,523 | 10.41 | 9.63 | 953,372 |
| November | 14.23 | 13.01 | 24,112,088 | 10.77 | 9.93 | 748,182 |
| December | 14.68 | 13.26 | 32,588,962 | 10.96 | 9.69 | 2,101,026 |

### 7.1.2 Preferred Shares

*Series A Shares*

The Series A Shares are listed and posted for trading on the TSX under the symbol "AQN.PR.A". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).

| **2018** | **High (C$)** | **Low (C$)** | **Volume** |
|---|---|---|---|
| January | 24.73 | 23.60 | 58,735 |
| February | 24.34 | 23.81 | 36,163 |
| March | 24.17 | 23.51 | 94,273 |
| April | 24.06 | 23.49 | 44,095 |
| May | 24.01 | 23.66 | 176,934 |
| June | 23.88 | 22.67 | 45,375 |
| July | 23.59 | 23.20 | 25,066 |
| August | 23.68 | 23.37 | 31,736 |
| September | 23.74 | 23.22 | 182,477 |
| October | 24.21 | 22.66 | 29,932 |
| November | 23.40 | 21.00 | 47,787 |
| December | 21.00 | 18.59 | 118,580 |

*Series D Shares*

The Series D Shares are listed and posted for trading on the TSX under the symbol "AQN.PR.D". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series D Shares for the periods indicated (as quoted by the TSX).

| 2018 | High (C$) | Low (C$) | Volume |
|---|---|---|---|
| January | 25.65 | 25.10 | 11,878 |
| February | 25.18 | 24.60 | 17,574 |
| March | 24.99 | 24.05 | 86,688 |
| April | 24.90 | 24.50 | 31,279 |
| May | 25.20 | 24.65 | 22,610 |
| June | 25.10 | 24.25 | 36,488 |
| July | 25.18 | 24.94 | 13,728 |
| August | 25.20 | 25.01 | 26,345 |
| September | 25.11 | 24.62 | 34,772 |
| October | 25.10 | 23.83 | 53,868 |
| November | 24.81 | 23.05 | 41,331 |
| December | 23.74 | 21.60 | 48,568 |

### 7.1.3 Subordinated Notes

The Subordinated Notes are listed and posted for trading on the NYSE under the symbol "AQNA". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Subordinated Notes for the periods indicated (as quoted by the NYSE).

| 2018 | High ($) | Low ($) | Volume |
|---|---|---|---|
| October (beginning October 23, 2018) | 25.55 | 25.17 | 1,169,005 |
| November | 25.67 | 25.13 | 1,099,494 |
| December | 25.47 | 23.99 | 1,040,284 |

## 7.2 Prior Sales

During the year ended December 31, 2018, there were no issuances or sales of any class of APUC securities that are outstanding but not listed or quoted on a marketplace.

## 7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

There are no securities of APUC that are, to APUC's knowledge, held in escrow or subject to contractual restrictions on transfer as of the date of this AIF.

# 8. DIRECTORS AND OFFICERS

## 8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with the Corporation.

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| CHRISTOPHER J. BALL<br>Toronto, Ontario, Canada | Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are boutique investment banking firms. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a member of the Hydrovision International Advisory Board, was a director of Clean Energy BC, is a director of First Nations Power Authority and is a recipient of the Clean Energy BC Lifetime Achievement Award. Mr. Ball is a holder of the Institute of Corporate Directors Director designation. | Director of APUC since October 27, 2009<br>Trustee of APCo from October 22, 2002 until May 12, 2011 |
| DAVID BRONICHESKI<br>Oakville, Ontario, Canada | Mr. Bronicheski is the Chief Financial Officer of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA (University of Toronto, Rotman School of Management). He is also a Chartered Accountant and a Chartered Professional Accountant. | Officer of APUC since October 27, 2009<br>Officer of APCo since September 17, 2007 |
| CHRISTOPHER K. JARRATT<br>Oakville, Ontario, Canada | Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors and is Vice Chair of APUC. Mr. Jarratt is a founder and principal of APCI, a private independent power developer formed in 1988 which is the predecessor organization to APCo and APUC. Between 1997 and 2009, Mr. Jarratt was a principal in Algonquin Power Management Inc. which managed APCo (formerly Algonquin Power Income Fund). Since 2009, Mr. Jarratt has been a Board member and served as Vice Chair of APUC. Prior to 1988, Mr. Jarratt was a founder and principal of a consulting firm specializing in renewable energy project development and environmental approvals. Mr. Jarratt earned an Honours Bachelor of Science degree from the University of Guelph in 1981 specializing in water resources engineering and holds an Ontario Professional Engineering designation. Additionally, Mr. Jarratt holds a Chartered Director certification from the Directors College (McMaster University. Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award. | Director and Officer of APUC since October 27, 2009<br>Officer of APCo since June 22, 2011 |
| ANTHONY (JOHNNY) JOHNSTON<br>Toronto, Ontario, Canada | Johnny Johnston is the Chief Operating Officer of APUC. Mr. Johnston has over 20 years of international experience in the utilities industry. Prior to joining the Corporation, Mr. Johnston, worked for National Grid where he led the transformation of its U.S. gas business. He has held a number of senior leadership roles in operations, customer service and strategy working in both the U.K. and U.S. across gas and electric businesses. Mr. Johnston has served on the board of the not-for-profit Heartshare Human Services of New York. Mr. Johnston holds a Masters degree in Engineering Science from the University of Oxford and a Master of Business Administration degree from the University of Cranfield. Mr. Johnston is a registered Chartered Engineer in the U.K. | Officer of APUC since January 8, 2019 |
| D. RANDY LANEY<br>Farmington, Arkansas, USA | D. Randy Laney was most recently Chairman of the board of directors of Empire from 2009 until APUC's acquisition of Empire on January 1, 2017. He joined the board of Empire in 2003 and served as the Non-Executive Vice Chairman from 2008 to 2009. Mr. Laney, semi-retired since 2008, has held numerous senior level positions with both public and private companies during his career, including 23 years with Wal-Mart Stores, Inc. in various executive positions such as Vice President of Finance, Benefits and Risk Management and Vice President of Finance and Treasurer. In addition, Mr. Laney has provided strategic advisory services to both private and public companies and served on numerous profit and non-profit boards. Mr. Laney brings significant management and capital markets experience, and strategic and operational understanding to his position on the Board. Mr. Laney holds a Bachelor of Science and a Juris Doctor from the University of Arkansas. | Director of APUC since February 1, 2017 |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| KENNETH MOORE<br>Toronto, Ontario, Canada | Kenneth Moore is the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., a Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University). | Director of APUC since October 27, 2009<br><br>Trustee of APCo from November 12, 1998 until November 10, 2010 |
| JEFF NORMAN<br>Burlington, Ontario, Canada | Jeff Norman is the Chief Development Officer of APUC, serving in this role since 2008. He was appointed to the APUC executive team in 2015. Mr. Norman co-founded the Algonquin Power Venture Fund in 2003 and served as President until it was acquired by APCo in 2008. Since 2008, the business development team has secured over 1 gigawatt of commercially secure renewable energy projects. Mr. Norman has over 24 years of experience and has reviewed the economic merits of hundreds of renewable energy projects located throughout North America. Mr. Norman holds a Bachelor of Arts (Chartered Accountancy) and a Masters of Accounting from the University of Waterloo. | Officer of APUC since May 25, 2015 |
| MARY ELLEN PARAVALOS<br>Oakville, Ontario, Canada | Mary Ellen Paravalos is the Chief Compliance and Risk Officer of APUC. Ms. Paravalos has over 20 years of international experience in the energy industry across operating, strategy and regulation & compliance areas. Prior to joining the Corporation, Ms. Paravalos was Vice President, ISO, Siting, and Compliance at Eversource Energy, and prior to that held a number of leadership roles at National Grid. Ms. Paravalos has served as a Director and President for the not-for-profit company New England Women in Energy and Environment. Ms. Paravalos holds a Masters degree in electric power engineering from Rensselaer Polytechnic Institute and a Bachelor's degree in electrical engineering from Northeastern University. Ms Paravalos is a registered engineer in the state of Massachusetts. | Officer of APUC since October 9, 2018 |
| DAVID PASIEKA<br>Oakville, Ontario, Canada | David Pasieka is the Chief Transformation Officer of APUC. As Chief Transformation Officer, Mr. Pasieka is focused on the Corporation's "Customer First" initiative, which is intended to establish a flexible and scalable platform to embrace new business models, enhance the customer experience, streamline business processes across the organization and increase employee productivity and efficiency through automation of processes and work procedures. Previously, Mr. Pasieka was the Chief Operating Officer of the Liberty Utilities Group. Mr. Pasieka has global experience in strategy, sales, marketing, integration, operations and customer service. He has led many organizations while integrating people, process and technology to encourage the steady growth of the organizations. Mr. Pasieka holds a Bachelor of Science from the University of Waterloo and a Masters of Business Administration from the Schulich School of Business – York University. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University). | Officer of APUC since September 1, 2011 |
| IAN E. ROBERTSON<br>Oakville, Ontario, Canada | Ian Robertson is the Chief Executive Officer of APUC. Mr. Robertson is a founder and principal of APCI, a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Robertson has almost 30 years of experience in the development of electric power generating projects and the operation of diversified regulated utilities. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. Mr. Robertson earned a Master of Business Administration degree from York University and holds a Chartered Financial Analyst designation. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University), as well as a Global Professional Master of Laws degree from the University of Toronto. Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association. | Director and Officer of APUC since October 27, 2009<br><br>Trustee of APCo since May 12, 2011<br><br>Officer of APCo since June 22, 2011 |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| MASHEED SAIDI<br>Dana Point, California, United States | Masheed Saidi has over 30 years of operational and business leadership experience in the electric utility industry. Between 2010 and 2017, Ms. Saidi was an Executive Consultant of Energy Initiatives Group, a specialized group of experienced professionals that provide technical, commercial and business consulting services to utilities, ISOs, government agencies and other organizations in the energy industry. Between 2005 and 2010, Ms. Saidi was the Chief Operating Officer and Executive Vice President of U.S. Transmission for National Grid USA, for which she was responsible for all aspects of the U.S. transmission business. Ms. Saidi previously served as Chairperson of the board of directors for the non-profit organization Mary's Shelter, and also previously served on the board of directors of the Northeast Energy and Commerce Association. She earned her Bachelors in Power System Engineering from Northeastern University and her Masters of Electrical Engineering from the Massachusetts Institute of Technology. She is a Registered Professional Engineer in the state of Massachusetts. | Director of APUC since June 18, 2014 |
| DILEK SAMIL<br>Las Vegas, Nevada, United States | Dilek Samil has over 30 years of finance, operations and business experience in both the regulated energy utility sector as well as wholesale power production. Ms. Samil joined NV Energy as Chief Financial Officer and retired as Executive Vice President and Chief Operating Officer. While at NV Energy, Ms. Samil completed the financial transformation of the company, bringing its financial metrics in line with those of the industry. As Chief Operating Officer, Ms. Samil focused on enhancing the company's safety and customer care culture. Prior to her role at NV Energy, Ms. Samil gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power. During her tenure at CLECO, the company completed construction of its largest generating unit and successfully completed its first rate case in over 10 years. Ms. Samil also served as CLECO's Chief Financial Officer at a time when the industry and the company faced significant turmoil in the wholesale markets. She led the company's efforts in the restructuring of its wholesale and power trading activities. Prior to NV Energy and CLECO, Ms. Samil spent about 20 years at NextEra where she held positions of increasing responsibility, primarily in the finance area. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida. | Director of APUC since October 1, 2014 |
| MELISSA STAPLETON BARNES<br>Carmel, Indiana, United States | Melissa Stapleton Barnes has been Senior Vice President, Enterprise Risk Management, and Chief Ethics and Compliance Officer for Eli Lilly and Company since January 2013. In this role, she is an executive officer and serves as a member of the company's executive committee. She previously held the role of Vice President, Deputy General Counsel from 2012 to 2013; and General Counsel, Lilly Diabetes and Lilly Oncology and Senior Director and Assistant General Counsel from 2010 - 2012. She holds a Bachelor of Science in Political Science & Government (highest distinction) from Purdue University and a Juris Doctorate from Harvard Law School. Ms. Barnes is a member of several professional organizations including Ethisphere – Business Ethics Leadership Alliance; CEB, Corporate Ethics Leadership Council; Healthcare Businesswomen's Association; and is a licensed attorney with the Indiana State Bar. Other board positions include The Center for the Performing Arts (Chair), The Great American Songbook Foundation and Timmy Global Health. | Director of APUC since June 9, 2016 |
| GEORGE L. STEEVES<br>Aurora, Ontario, Canada | George Steeves has been Senior Project Manager of True North Energy, an energy consulting firm specializing in the provision of technical and financial due diligence services for renewable energy projects, since July 2017. From April 2002 to July 2017, Mr. Steeves was principal of True North Energy. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the President of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a chair, director and/or audit committee member of public and private companies, including the Corporation, and formerly Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University and holds a Professional Engineering designation in Ontario and British Columbia. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University). | Director of APUC since October 27, 2009<br><br>Trustee of APCo from September 8, 1997 until May 12, 2011 |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| JENNIFER TINDALE<br>Campbellville, Ontario, Canada | Jennifer Tindale is the Chief Legal Officer of APUC. Ms. Tindale has over 20 years of experience advising public companies on acquisitions, dispositions, mergers, financings, corporate governance and disclosure matters. From July 2011 to February 2017, Ms. Tindale was the Executive Vice President, General Counsel & Secretary at a cross-listed real estate investment trust. Prior to that, she was Vice President, Associate General Counsel & Corporate Secretary at a public Canadian-based pharmaceutical company and before that she was a partner at a top tier Toronto law firm, practising corporate securities law. Ms. Tindale holds a Bachelor of Arts and a Bachelor of Laws from the University of Western Ontario. | Officer of APUC since February 7, 2017 |
| GEORGE TRISIC<br>Oakville, Ontario, Canada | George Trisic is the Chief Administration Officer and Corporate Secretary of APUC. He has broad experience managing in high growth, start up and expanding businesses across multiple sites and regions. In his role, Mr. Trisic is responsible for the human resources and corporate secretarial functions of the Corporation. His skill set includes leading multi-functional groups in finance, human resources, legal and information technology in a senior role. Mr. Trisic holds a Bachelor of Laws Degree from the University of Western Ontario. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University). | Officer of APUC since November 4, 2013 |

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his or her successor is elected in accordance with the by-laws of APUC.

To the knowledge of the Corporation, as at February 27, 2019, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 4,055,003 Common Shares, representing less than 1% of the total number of issued and outstanding Common Shares before giving effect to the exercise of options to purchase Common Shares held by such directors and executive officers.

## 8.2 Audit Committee

Under the by-laws of APUC, the directors may appoint from their number, committees to effect the administration of the director's duties. The directors have established an Audit Committee currently comprised of four directors of APUC: Mr. Ball (Chair), Ms. Stapleton Barnes, Mr. Laney and Ms. Samil, all of whom are independent and financially literate for purposes of National Instrument 52-110 - *Audit Committees*. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

### 8.2.1 Audit Committee Charter

The Audit Committee mandate is attached as Schedule F to this AIF.

### 8.2.2 Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as directors of APUC, of each member of the Audit Committee that is relevant to the performance of their responsibilities as a member of the Audit Committee.

Mr. Ball's financial experience includes over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Laney's financial experience includes a number of senior executive roles with Wal-Mart Stores, Inc. including roles as Vice President, Finance and Treasurer and as Vice President Finance, Benefits and Risk Management. Mr. Laney also served as a member of the Empire board of directors commencing in 2003 and acted as Chair of the Empire board from 2009 until APUC's acquisition of Empire on January 1, 2017. Mr. Laney was also a member of the Audit Committee of Empire from May 2003 to April 2005.

Ms. Samil has extensive financial experience, with over 30 years of finance, operations and business experience in the regulated energy utility sector. During her career, Ms. Samil was the Executive Vice President and Chief Operating Officer of NV Energy and gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power LLC. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.

Ms. Stapleton Barnes' financial experience includes a number of risk management and legal/regulatory senior executive roles in a public company. Ms. Stapleton Barnes is currently an executive officer and a member of the corporate executive committee of Eli-Lilly and Company. She has extensive experience in the areas of risk management, legal and regulatory and is a licensed attorney with the Indiana State Bar.

### 8.2.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy requiring pre-approval by the Audit Committee of all audit and permitted non-audit services provided to APUC by its external auditor. The Audit Committee may delegate pre-approval authority to a member of the Audit Committee; however, the decisions of any member of the Audit Committee to whom this authority has been delegated must be presented to the full Audit Committee at its next scheduled Audit Committee meeting.

| Services | 2018 Fees (C$) | 2017 Fees (C$) |
|---|---|---|
| Audit Fees[1] | 4,245,342 | 3,947,930 |
| Audit-Related Fees[2] | 85,500 | 100,235 |
| Tax Fees[3] | 494,448 | 252,535 |
| Other Fees | Nil | Nil |

1 For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements.

2 For assurance and related services that are reasonably related to the performance of the audit or review of APUC's financial statements and not reported under Audit Fees, including audit procedures related to regulatory commission filings.

3 For tax advisory, compliance and planning services.

## 8.3 Corporate Governance, Risk, and Human Resources and Compensation Committees

The Board has established a Corporate Governance Committee, currently comprised of four directors of APUC: Mr. Steeves (Chair), Mr. Moore, Ms. Saidi, and Mr. Jarratt.

The Board has established a Risk Committee to assist the Board in the oversight of the Corporation's enterprise risk management approach. The committee is currently comprised of four directors of APUC: Ms. Saidi (Chair), Ms. Stapleton Barnes, Mr. Jarratt and Mr. Steeves.

The Board has also established a Human Resources and Compensation Committee, currently comprised of three directors of APUC: Ms. Samil (Chair), Mr. Ball and Mr. Laney.

## 8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media company. Telephoto Technologies Inc. was placed into receivership in August 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April 2010.

## 8.5 Conflicts of Interest

To the knowledge of the Corporation, there are no existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary of APUC.

# 9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

## 9.1 Legal Proceedings

The Corporation is not, and was not during the financial year ended December 31, 2018, party to any legal proceedings that involve a claim for damages equal to 10% or more of the current consolidated assets of the Corporation, and the Corporation is not aware of any such legal proceedings that are contemplated.

## 9.2 Regulatory Actions

During the financial year ended December 31, 2018, there were:

a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; and

c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

# 10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed elsewhere in this AIF, no director, executive officer or 10% holder of voting securities, or any associate or affiliate of the foregoing has, or has had, any material interest in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC or any of its affiliates.

# 11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares, the Series A Shares and the Series D Shares listed on the TSX is AST Trust Company (Canada), at its offices in Toronto, Ontario.

The transfer agent and registrar for the Common Shares listed on the NYSE is AST American Stock Transfer & Trust Company, LLC, at its office in Brooklyn, New York.

# 12. MATERIAL CONTRACTS

The Corporation does not have any material contracts that were not entered into in the ordinary course of business of the Corporation.

# 13. EXPERTS

Ernst & Young LLP is the external auditor of the Corporation and has confirmed that it is independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that it is an independent accountant with respect to the Corporation under all relevant U.S. professional and regulatory standards.

# 14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and MD&A for the fiscal year ended December 31, 2018, which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

# SCHEDULE A

**Selected Operating Hydroelectric, Solar and Wind Facilities of the Liberty Power Group**

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | PPA/Hedge Expiry Year |
|---|---|---|---|---|
| **Facility**:<br>St. Leon Wind Facility<br><br>**Owner**:<br>St. Leon Wind Energy LP | 103.9 | St. Leon, Manitoba | Manitoba Hydro | 2026 + one 5 year extension |
| **Facility:**<br>Amherst Island Wind Facility<br><br>**Owner**:<br>Windlectric Inc. | 75 | Stella, Ontario | IESO | 2036 |
| **Facility:**<br>Minonk Wind Facility<br><br>**Owner**:<br>Minonk Wind, LLC | 200 | Minonk, Illinois | PJM North Illinois | 2024 [1] |
| **Facility:**<br>Senate Wind Facility<br><br>**Owner:**<br>Senate Wind, LLC | 150 | Graham, Texas | ERCOT North markets | 2027 [1] |
| **Facility:**<br>Sandy Ridge Wind Facility<br><br>**Owner:**<br>Sandy Ridge Wind, LLC | 50 | Centre County, Pennsylvania | PJM West | 2028 [1] |
| **Facility:**<br>Shady Oaks Wind Facility<br><br>**Owner:**<br>GSG 6, LLC | 109.5 | Lee County, Illinois | Commonwealth Edison | 2032 |
| **Facility:**<br>Odell Wind Facility<br><br>**Owner**:<br>Odell Wind Farm, LLC. | 200 | Cottonwood, Jackson, Martin and Watonwan Counties, Minnesota | Northern States Power | 2036 |
| **Facility:**<br>Deerfield Wind Facility<br><br>**Owner**:<br>Deerfield Wind Energy, LLC | 149 | Central Michigan | Wolverine Power Supply Co-operative | 2037 |
| **Facility:**<br>Bakersfield I Solar Facility<br><br>**Owner**:<br>Algonquin SKIC20 Solar, LLC | 20 | Kern County, California | Pacific Gas & Electric Company | 2035 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | PPA/Hedge Expiry Year |
|---|---|---|---|---|
| **Facility:**<br>Great Bay Solar Facility<br><br>**Owner**:<br>Great Bay Solar I, LLC | 75 | Somerset County, Maryland | U.S. General Services Administration | 2028 |
| **Facility:**<br>Tinker Hydro Facility<br><br>**Owner**:<br>Algonquin Tinker Gen Co. | 34 | Perth-Andover, New Brunswick | Algonquin Energy Services Inc. & Town of Perth-Andover | Perth-Andover Contract through 2031 |

(1) The Corporation currently has hedge agreements in place in respect of each facility. See “Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Selected Facilities”.

# SCHEDULE B

**Selected Operating Thermal Facilities of the Liberty Power Group**

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | PPA Expiry Year |
|---|---|---|---|---|
| **Facility:**<br>Sanger Facility<br><br>**Owner**:<br>Algonquin Power Sanger LLC | 56 | Sanger, California | Pacific Gas & Electric Company | 2021 |
| **Facility:**<br>Windsor Locks Thermal Facility<br><br>**Owner**:<br>Algonquin Power Windsor Locks LLC | 71 | Windsor Locks, Connecticut | ISO New England Ahlstrom Corporation | 2027 |

# SCHEDULE C

**Selected Operating Wastewater and Water Distribution Facilities of the Liberty Utilities Group**

| Utility | Owner | Location | Type of Utility | Rates[1] |
|---|---|---|---|---|
| LPSCo Water & Waste System | Liberty Utilities (Litchfield Park Water & Sewer) Corp. | Litchfield, Park, Arizona | Wastewater<br>Water Distribution | Pursuant to ACC docket 76799 |
| Pine Bluff Water System | Liberty Utilities (Pine Bluff Water) Inc. | Pine Bluff, Arkansas | Water Distribution | Pursuant to APSC docket No. 14-020-U |
| Liberty Utilities (Park Water) Corp. | Western Water Holdings, LLC | Downey, California | Water Distribution | Pursuant to CPUC decision 16-01-009 |
| Liberty Utilities (Apple Valley Ranchos Water) Corp. | Liberty Utilities (Park Water) Corp. | Apple Valley, California | Water Distribution | Pursuant to CPUC decision 15-11-030 |
| Empire | The Empire District Electric Company | Joplin, Missouri | Distribution | MO – WR-2012-0300 |

(1) See www.libertyutilities.com for complete rate tariffs.

# SCHEDULE D

**Selected Operating Electrical Distribution Facilities of the Liberty Utilities Group**

| Utility | Owner | Location | Type of Utility | Rates[1] |
|---|---|---|---|---|
| CalPeco Electric System | Liberty Utilities (CalPeco Electric) LLC | Lake Tahoe, California | Electricity Distribution | Rates pursuant to CPUC decision 16-12-024 |
| Granite State Electric System | Liberty Utilities (Granite State Electric) Corp | Salem, New Hampshire | Electricity Distribution | Rates pursuant to NHPUC docket DE 16-383, Order 26,005 |
| Empire District Electric System | The Empire District Electric Company | Joplin, Missouri | Electricity Generation, Transmission & Distribution | MO - ER-2016-0023<br>AR - 13-111-U<br>KS - 11-EPDE-856-RTS<br>OK - PUD 201600468 |

(1) See www.libertyutilities.com for complete rate tariffs.

# SCHEDULE E

**Selected Operating Natural Gas Distribution Facilities of the Liberty Utilities Group**

| Utility | Owner | Location | Type of Utility | Rates[1] |
|---|---|---|---|---|
| EnergyNorth Gas System | Liberty Utilities (EnergyNorth Natural Gas) Corp. | Londonderry, New Hampshire | Natural Gas Distribution | Rates pursuant to NHPUC docket DG 17-048, Order 26,122 and Order 26,187 |
| Peach State Gas System | Liberty Utilities (Peach State Natural Gas) Corp. | Columbus, Gainesville, Georgia | Natural Gas Distribution | Rates pursuant to GPSC docket #34734 Document #171047 |
| New England Gas System | Liberty Utilities (New England Natural Gas Company) Corp. | Fall River, North Attleboro, Plainville, Westport, Swansea, Somerset, Massachusetts | Natural Gas Distribution | Rates pursuant to M.D.P.U 18-15 |
| Midstates Gas System - Illinois | Liberty Utilities (Midstates Natural Gas) Corp. | Salem, Virden, Vandalia, Xenia, Metropolis, Illinois | Natural Gas Distribution | Rates pursuant to ICC Docket IL-16-0401 |
| Midstates Gas System - Iowa | Liberty Utilities (Midstates Natural Gas) Corp. | Keokuk, Iowa | Natural Gas Distribution | Rates pursuant to IUB decision RPU-2016-0003 |
| Midstates Gas System - Missouri | Liberty Utilities (Midstates Natural Gas) Corp. | Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri | Natural Gas Distribution | Rates pursuant to MOPSC decision GR-2018-0013 |
| New Hampshire Gas System | Liberty Utilities (EnergyNorth Natural Gas) Corp. | Keene, New Hampshire | Propane Gas Distribution | Rates pursuant to NHPUC docket DG 09-038 |
| Empire District Gas System | EDG | Joplin, Missouri | Natural Gas Distribution | MO - GR-2009-0434 |

(1) See www.libertyutilities.com for complete rate tariffs.

# SCHEDULE F

**ALGONQUIN POWER & UTILITIES CORP.**

**MANDATE OF THE AUDIT COMMITTEE**

By appropriate resolution of the board of directors (the " **Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the " **Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

**1. PURPOSE**

1.1 The Committee's purpose is to:

a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis (" **MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

**2. COMMITTEE MEMBERSHIP**

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

a) be a director of the Corporation;

b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates; and

c) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators ("**NI 52 110**") and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under NI 52 110 and other applicable laws and regulations.

2.4 Chair – The Chair of the Committee shall be selected from among the members of the Committee.

2.5 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

**3. COMMITTEE MEETINGS**

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly and meetings of the Committee shall be convened whenever requested by the external auditors or any member of the Committee in accordance with the Canada Business Corporations Act. No business may be transacted by the Committee at a meeting unless a quorum of a majority of the members of the Committee is present. The Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall hold *in camera* meetings, and shall also meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

a) representatives of Management;

b) the external auditor; and

c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to receive notice of every Committee meeting and to be heard and attend thereat at the Corporation's expense. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

**4. COMMITTEE AUTHORITY AND RESOURCES**

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation's internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such outside legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this mandate.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

**5. REMUNERATION OF COMMITTEE MEMBERS**

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

**6. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE**

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) Interim Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) Prospectuses and Other Documents – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management's disclosures along with any significant proposed modifications by the auditors that were not included;

B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

D) major issues regarding financial statement presentations;

E) any significant changes in the Corporation's selection or application of accounting principles;

F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

A) review earnings releases, and review and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

b) External Auditor

(i) Authority with Respect to External Auditor – As a representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, for determining whether at any time the incumbent external auditor should be removed from office, and for determining the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

B) In accordance with applicable laws and regulations, the Committee shall pre-approve any non-audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non-audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Committee may delegate to one or more designated members of the Committee, such designated members not being members of management, the authority to approve additional non-audit services that arise between Committee meetings, provided that such designated members report any such approvals to the Committee at the next scheduled meeting.

C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

B) any changes required in the planned scope of the internal audit; and

C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.

c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems advisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to assess compliance by the Corporation with its loan covenants and restrictions, if any.

e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non-compliance by the Corporation with applicable laws and regulations.

f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

g) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

h) Liaison – The Committee shall assess whether appropriate liaison and co−operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

i) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

j) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

**7. REPORTING TO THE BOARD**

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

**8. EVALUATION OF COMMITTEE PERFORMANCE**

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Mandate

a) Review by Committee – The Committee shall periodically review and discuss the adequacy of this mandate and if applicable, recommend any proposed changes to the Board.

b) Review by Board – The Board will review and reassess the adequacy of the mandate periodically, as it considers appropriate.

**9. LEGISLATIVE AND REGULATORY CHANGES**

9.1 Compliance – It is the Board's intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this mandate shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least every fourteen months to reflect such amendments.

**10. CURRENCY OF MANDATE**

10.1 Currency of Mandate – This mandate was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010. Last updated on March 1, 2018.

# SCHEDULE G

## GLOSSARY OF TERMS

In this AIF, the following terms have the meanings set forth below, unless otherwise indicated:

"**AAGES**" has the meaning ascribed thereto under "General Development of the Business – Corporate Development".

"**AAGES Secured Credit Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**Abengoa**" has the meaning ascribed thereto under "General Development of the Business – Corporate Development".

"**ACC**" means the Arizona Corporation Commission.

"**Additional Atlantica Investment**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**AESO**" means Alberta Electric System Operator.

"**AIF**" means this annual information form.

"**Amended and Restated Rights Plan**" has the meaning ascribed thereto under "Description of Capital Structure – Shareholders' Rights Plan".

"**Amherst Island Wind Facility**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Wind Power Generating Facilities – Selected Facilities".

"**APCI**" means Algonquin Power Corporation Inc.

"**APCo**" has the meaning ascribed thereto under "Corporate Structure – Name, Address and Incorporation".

"**APSC**" means Arkansas Public Services Commission.

"**APUC**" has the meaning ascribed thereto under "Corporate Structure – Name, Address and Incorporation".

"**Atlantica**" has the meaning ascribed thereto under "General Development of the Business".

"**ATN3**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**ATN3 Project**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**AY Holdings**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships".

"**Bakersfield I Solar Facility**" means the 20 MW Bakersfield solar generating facility in California.

"**Bakersfield II Solar Facility**" means the 10 MW Bakersfield solar generating facility in California.

"**Blue Hill Wind Project**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Business Development – Current Development and Construction Projects".

"**Board**" means the Algonquin Power & Utilities Corp. board of directors.

"**Broad Mountain Wind Project**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Liberty Power".

"**BRRBA**" means base revenue requirement balancing account.

"**CalPeco Electric System**" means an electricity distribution utility in the Lake Tahoe basin and surrounding areas.

"**COD**" means commercial operation date.

"**Collateral Reset Level**" has the meaning ascribed thereto under "Enterprise Risk Factors – Risk Factors Relating to Strategic Planning and Execution".

"**Common Shares**" means the common shares of Algonquin Power & Utilities Corp.

"**Cornwall Solar Facility**" means the solar generating facility in Cornwall, Ontario.

"**Corporation**" has the meaning ascribed thereto under "Corporate Structure - Name, Address and Incorporation".

"**Corporation Credit Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**CPUC**" means California Public Utilities Commission.

"**DBRS**" means the credit rating agency Dominion Bond Rating Service Limited.

"**Debentures**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 – Corporate".

"**Deerfield Wind Facility**" means the Deerfield wind energy facility in Michigan.

"**Default Service**" has the meaning ascribed thereto under "Description of the Business – Liberty Utilities Group – Electric Distribution Systems – Selected Facilities".

"**ECAC**" means energy cost adjustment clause.

"**EDG**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships".

"**EGNB**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Liberty Utilities Group".

"**EGNB Acquisition**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Liberty Utilities Group".

"**Empire**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships".

"**Empire Acquisition**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 – Corporate".

"**Empire Acquisition Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 – Corporate".

"**Empire District Electric System**" means an electricity distribution utility in Missouri, Kansas, Oklahoma and Arkansas.

"**EnergyNorth Gas System**" means a natural gas distribution utility in New Hampshire.

"**EPC**" means engineering, procurement and construction.

"**ERCOT**" means Electric Reliability Council of Texas.

"**ERM**" means enterprise risk management.

"**FERC**" means the Federal Energy Regulatory Commission.

"**FIT**" means feed-in tariff.

"**Fitch**" means Fitch Ratings, Inc.

"**GAAP**" means Generally Accepted Accounting Principles.

"**GAF**" has the meaning ascribed thereto under "Description of the Business – Liberty Utilities Group – Description of Operations – Natural Gas Distribution Systems – Selected Facilities".

"**Granite Bridge Project**" has the meaning ascribed thereto under "Description of the Business – Liberty Utilities Group – Business Development".

"**Granite State Electric System**" means an electricity distribution utility in New Hampshire.

"**Great Bay Solar Facility**" means the 75 MW Great Bay solar facility in Somerset County, Maryland.

"**Great Bay II Solar Project**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Business Development – Current Development and Construction Projects".

"**GW**" means gigawatt.

"**IESO**" means Independent Electricity System Operator for Ontario.

"**Initial Atlantica Investment**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Corporate".

"**Interest Reset Date**" has the meaning ascribed thereto under "Description of Capital Structure – Subordinated Notes".

"**ISO**" means independent system operator.

"**ISO-NE**" means Independent System Operator New England.

"**JPMVEC**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Selected Facilities".

"**KCC**" means State Corporation Commission of the State of Kansas.

"**kV**" means kilovolt.

"**Liberty Park Water**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 – Liberty Utilities Group".

"**Liberty Park Water System**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 – Liberty Utilities Group".

"**Liberty Power Bilateral Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Liberty Power Group".

"**LIBOR**" has the meaning ascribed thereto in the first supplemental indenture dated as of October 17, 2018 between APUC, American Stock Transfer & Trust Company, LLC and AST Trust Company (Canada) providing for the issue of the Subordinated Notes.

"**LPSCo System**" means the Litchfield Park water and wastewater system in Arizona.

"**LU Canada**" has the meaning ascribed thereto under "Corporate Structure - Intercorporate Relationships".

"**Luning Solar Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Liberty Utilities Group".

"**Manitoba Hydro**" means the Manitoba Hydro-Electric Board.

"**MD&A**" has the meaning ascribed thereto under "Non-GAAP Financial Measures".

"**MDPU**" means The Massachusetts Department of Public Utilities.

"**Midstates Gas Systems**" means natural gas distribution utility assets in Missouri, Iowa and Illinois.

"**Minonk Wind Facility**" means the Minonk wind energy facility in Illinois.

"**MISO**" means Midcontinent Independent System Operator, Inc.

"**Moody's**" means Moody's Investors Services, Inc.

"**MPSC**" means Missouri Public Services Commission.

"**MW**" means megawatt.

"**MWh**" means megawatt hours.

"**NERC**" means the North American Electric Reliability Corporation.

"**Net Energy Sales**" has the meaning ascribed thereto under "Non-GAAP Financial Measures".

"**Net Utility Sales**" has the meaning ascribed thereto under "Non-GAAP Financial Measures".

"**New England Gas System**" means natural gas distribution utility assets in Massachusetts.

"**NHPUC**" means the New Hampshire Public Utilities Commission.

"**NV Energy**" means NV Energy, Inc.

"**NYSE**" means New York Stock Exchange.

"**OATT**" means open access transmission tariff.

"**OCC**" means Corporation Commission of Oklahoma.

"**Odell Wind Facility**" means the 200 MW Odell wind facility in Cottonwood, Jackson, Martina and Watonwan counties in Minnesota.

"**OPEB**" has the meaning ascribed thereto under "Enterprise Risk Factors – Risk Factors Relating to Financing and Financial Reporting".

"**Peach State Gas System**" means natural gas distribution utility assets in Georgia.

"**PGA**" means purchased gas adjustment.

"**PJM**" means PJM Interconnection.

"**PPA**" means power purchase agreement.

"**Primary Energy Production Hedge**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Selected Facilities".

"**PTC**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 – Liberty Power Group".

"**REC**" means a renewable energy credit.

"**Reinvestment Plan**" has the meaning ascribed thereto under "Dividends – Dividend Reinvestment Plan".

"**RPS**" means renewable portfolio standards.

"**S&P**" means Standard & Poor's Financial Services LLC.

"**Sandy Ridge Wind Facility**" means the Sandy Ridge wind energy facility in Texas.

"**Sandy Ridge II Wind Project**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Business Development – Current Development and Construction Projects".

"**Senate Wind Facility**" means the Senate wind energy facility in Texas.

"**Series A Shares**" has the meaning ascribed thereto under "Dividends – Preferred Shares".

"**Series A Shares Redemption Right**" has the meaning ascribed thereto under "Description of Capital Structure – Preferred Shares".

"**Series B Shares**" has the meaning ascribed thereto under "Description of Capital Structure – Preferred Shares".

"**Series C Shares**" has the meaning ascribed thereto under "Dividends – Preferred Shares".

"**Series D Shares**" has the meaning ascribed thereto under "Dividends – Preferred Shares".

"**Series E Shares**" has the meaning ascribed thereto under "Description of Capital Structure – Preferred Shares".

"**Series F Shares**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**Shady Oaks Wind Facility**" means the Shady Oaks wind energy facility in Illinois.

"**Shady Oaks II Wind Project**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Business Development – Current Development and Construction Projects".

"**SLG**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Liberty Utilities Group".

"**SPP**" means Southwest Power Pool.

"**St. Leon LP**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships – Subsidiaries".

"**St. Leon Wind Facility**" means the 104 MW wind facility located at St. Leon, Manitoba.

"**Subordinated Notes**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**Sugar Creek Wind Project**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Liberty Power Group".

"**Tinker Hydro Facility**" means the electric generating facility and transmission assets in New Brunswick .

"**TSX**" means the Toronto Stock Exchange.

"**Val-Éo Wind Project**" has the meaning ascribed thereto under "Description of the Business – Liberty Power Group – Business Development – Current Development and Construction Projects".

"**Walker Ridge Wind Project**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Liberty Power Group".

"**Wataynikaneyap Power Transmission Project**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – 2019 – Liberty Utilities Group".

"**Windsor Locks Thermal Facility**" has the meaning ascribed thereto under the heading "Description of the Business – Liberty Power Group – Description of Operations – Thermal (Cogeneration) Electric Generating Facilities – Selected Facilities".

**Consolidated Financial Statements of**
**Algonquin Power & Utilities Corp.**
**For the years ended December 31, 2018 and 2017**

# 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, 2018, 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, 2018.

February 28, 2019

| | |
|---|---|
| /s/ Ian Robertson | /s/ David Bronicheski |
| Chief Executive Officer | Chief Financial Officer |

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

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

***Opinion on the Consolidated Financial Statements***

We have audited the accompanying consolidated balance sheets of Algonquin Power & Utilities Corp. (the "Company") as of December 31, 2018 and December 31, 2017, the related consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2018 and December 31, 2017, and the results of its operations and its cash flows for the years then ended in conformity with United States generally accepted accounting principles.

***Report on Internal Control over Financial Reporting***

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 28, 2019 expressed an unqualified opinion thereon.

***Basis for Opinion***

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and the significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our audit opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2013.

Toronto, Canada
February 28, 2019

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

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

***Opinion on Internal Control over Financial Reporting***

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2018, 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"). In our opinion, Algonquin Power & Utilities Corp. (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets as at December 31, 2018 and December 31, 2017, and the consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes, and our report dated February 28, 2019 expressed an unqualified opinion thereon.

***Basis for Opinion***

The Company'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. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

***Definition and Limitations of Internal Control Over Financial Reporting***

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.

/s/ Ernst & Young LLP

Toronto, Canada
February 28, 2019

## Algonquin Power & Utilities Corp.
## Consolidated Balance Sheets

*(thousands of U.S. dollars)*

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 46,819 | $ 43,484 |
| Accounts receivable, net (note 4) | 245,728 | 244,617 |
| Fuel and natural gas in storage | 43,063 | 44,414 |
| Supplies and consumables inventory | 52,537 | 45,074 |
| Regulatory assets (note 7) | 59,037 | 66,567 |
| Prepaid expenses | 27,283 | 31,005 |
| Derivative instruments (note 23) | 9,616 | 16,099 |
| Other assets and long-term investments (notes 8 and 11) | 7,522 | 7,110 |
| | 491,605 | 498,370 |
| Property, plant and equipment, net (note 5) | 6,393,558 | 6,304,897 |
| Intangible assets, net (note 6) | 54,994 | 51,103 |
| Goodwill (note 6) | 954,282 | 954,282 |
| Regulatory assets (note 7) | 391,437 | 374,959 |
| Derivative instruments (note 23) | 53,192 | 54,115 |
| Long-term investments (note 8) | | |
| Investment carried at fair value | 814,530 | — |
| Notes receivable from equity investees | 101,416 | 30,060 |
| Other long-term investments | 32,955 | 37,271 |
| Deferred income taxes (note 18) | 72,415 | 61,357 |
| Other assets (note 11) | 28,584 | 29,153 |
| | $ 9,388,968 | $ 8,395,567 |

## Algonquin Power & Utilities Corp.
## Consolidated Balance Sheets

*(thousands of U.S. dollars)*

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 89,740 | $ 119,887 |
| Accrued liabilities | 235,586 | 280,144 |
| Dividends payable (note 15) | 62,613 | 50,445 |
| Regulatory liabilities (note 7) | 39,005 | 37,687 |
| Long-term debt (note 9) | 13,048 | 12,364 |
| Other long-term liabilities (note 12) | 42,337 | 46,754 |
| Derivative instruments (note 23) | 14,339 | 14,126 |
| Other liabilities | 2,313 | 2,623 |
| | 498,981 | 564,030 |
| Long-term debt (note 9) | 3,323,747 | 3,067,187 |
| Regulatory liabilities (note 7) | 539,587 | 538,437 |
| Deferred income taxes (note 18) | 444,145 | 399,148 |
| Derivative instruments (note 23) | 88,503 | 54,818 |
| Pension and other post-employment benefits obligation (note 10) | 191,915 | 168,189 |
| Other long-term liabilities (note 12) | 263,582 | 242,105 |
| | 4,851,479 | 4,469,884 |
| Redeemable non-controlling interests (note 17) | | |
| Redeemable non-controlling interests, held by related party | 307,622 | — |
| Redeemable non-controlling interests | 33,364 | 41,553 |
| Equity: | | |
| Preferred shares (note 13(b)) | 184,299 | 184,299 |
| Common shares (note 13(a)) | 3,562,418 | 3,021,699 |
| Additional paid-in capital | 45,553 | 38,569 |
| Deficit | (595,259) | (524,311) |
| Accumulated other comprehensive loss (note 14) | (19,385) | (2,792) |
| Total equity attributable to shareholders of Algonquin Power & Utilities Corp. | 3,177,626 | 2,717,464 |
| Non-controlling interests (note 17) | 519,896 | 602,636 |
| Total equity | 3,697,522 | 3,320,100 |
| Commitments and contingencies (note 21) | | |
| Subsequent events (notes 8, 9, 13 and 23) | | |
| | $ 9,388,968 | $ 8,395,567 |

See accompanying notes to consolidated financial statements

## Algonquin Power & Utilities Corp.
## Consolidated Statements of Operations

| *(thousands of U.S. dollars, except per share amounts)* | Year ended December 31 2018 | 2017 |
|---|---|---|
| **Revenue** | | |
| Regulated electricity distribution | $ 831,196 | $ 763,501 |
| Regulated gas distribution | 430,377 | 376,806 |
| Regulated water reclamation and distribution | 128,437 | 140,082 |
| Non-regulated energy sales | 235,359 | 217,542 |
| Other revenue | 22,018 | 24,007 |
| | 1,647,387 | 1,521,938 |
| **Expenses** | | |
| Operating expenses | 472,466 | 450,231 |
| Regulated electricity purchased | 265,166 | 222,443 |
| Regulated gas purchased | 183,012 | 141,689 |
| Regulated water purchased | 8,796 | 9,503 |
| Non-regulated energy purchased | 27,164 | 19,590 |
| Administrative expenses | 52,710 | 49,640 |
| Depreciation and amortization | 260,772 | 251,314 |
| Loss (gain) on foreign exchange | (58) | 323 |
| | 1,270,028 | 1,144,733 |
| **Operating income** | 377,359 | 377,205 |
| Interest expense on long-term debt and others | 152,118 | 142,439 |
| Interest expense on convertible debentures and amortization of acquisition financing (notes 9(b) and 12(h)) | — | 13,383 |
| Change in value of investment carried at fair value (note 8(a)) | 137,957 | — |
| Interest, dividend, equity and other income (note 8) | (53,139) | (9,238) |
| Pension and post-employment non-service costs (note 10) | 3,914 | 9,035 |
| Other net losses | 2,725 | 664 |
| Acquisition-related costs, net (note 12(f)) | 687 | 47,708 |
| Loss (gain) on derivative financial instruments (note 23(b)(iv)) | 636 | (1,918) |
| | 244,898 | 202,073 |
| **Earnings before income taxes** | 132,461 | 175,132 |
| **Income tax expense (note 18)** | | |
| Current | 11,347 | 7,517 |
| Deferred | 42,025 | 65,910 |
| | 53,372 | 73,427 |
| **Net earnings** | 79,089 | 101,705 |
| Net effect of non-controlling interests (note 17) | | |
| Net effect of non-controlling interests | 108,521 | 47,770 |
| Net effect of non-controlling interests held by related party | (2,622) | — |
| **Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.** | $ 184,988 | $ 149,475 |
| Series A and D Preferred shares dividend (note 15) | 8,027 | 8,020 |
| **Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.** | $ 176,961 | $ 141,455 |
| Basic and diluted net earnings per share (note 19) | $ 0.38 | $ 0.37 |

See accompanying notes to consolidated financial statements

## Algonquin Power & Utilities Corp.
## Consolidated Statements of Comprehensive Income

| *(thousands of U.S. dollars)* | Year ended December 31 | |
|---|---|---|
| | **2018** | **2017** |
| Net earnings | $ 79,089 | $ 101,705 |
| Other comprehensive income (loss): | | |
| Foreign currency translation adjustment, net of tax recovery of $4,532 and $169, respectively (notes 1(v), 23(b)(iii) and 23(b)(iv)) | (27,969) | (21,753) |
| Change in fair value of cash flow hedges, net of tax recovery of $952 and expense of $599, respectively (note 23(b)(ii)) | (2,690) | 1,626 |
| Change in value of available-for-sale investments | — | (65) |
| Change in pension and other post-employment benefits, net of tax expense of $696 and $512, respectively (note 10) | 1,960 | 376 |
| Other comprehensive loss, net of tax | (28,699) | (19,816) |
| Comprehensive income | 50,390 | 81,889 |
| Comprehensive loss attributable to the non-controlling interests | (107,380) | (47,743) |
| Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp. | $ 157,770 | $ 129,632 |

See accompanying notes to consolidated financial statements

## Algonquin Power & Utilities Corp.
## Consolidated Statement of Equity

*(thousands of U.S. dollars)*
For the year ended December 31, 2018

| | Algonquin Power & Utilities Corp. Shareholders | | | | | Non-controlling interests | Total |
|---|---|---|---|---|---|---|---|
| | Common shares | Preferred shares | Additional paid-in capital | Accumulated deficit | Accumulated OCI | | |
| Balance, December 31, 2017 | $ 3,021,699 | $ 184,299 | $ 38,569 | $ (524,311) | $ (2,792) | $ 602,636 | $ 3,320,100 |
| Adoption of Topic 606 on revenue (note 1(s)) | — | — | — | 1,860 | — | — | 1,860 |
| Adoption of ASU 2018-02 on tax effects in AOCI (note 2(a)) | — | — | — | (10,625) | 10,625 | — | — |
| Net earnings (loss) | — | — | — | 184,988 | — | (105,899) | 79,089 |
| Redeemable non-controlling interests not included in equity (note 17) | — | — | — | — | — | 4,923 | 4,923 |
| Other comprehensive loss | — | — | — | — | (27,218) | (1,481) | (28,699) |
| Dividends declared and distributions to non-controlling interests | — | — | — | (187,890) | — | (9,393) | (197,283) |
| Dividends and issuance of shares under dividend reinvestment plan (note 13(a)(ii)) | 55,442 | — | — | (55,442) | — | — | — |
| Common shares issued pursuant to public offering, net of costs (note 13(a)(i)) | 472,180 | — | — | — | — | — | 472,180 |
| Common shares issued upon conversion of convertible debentures (note 12(h)) | 447 | — | — | — | — | — | 447 |
| Common shares issued pursuant to share-based awards (note 13(c)) | 12,650 | — | (4,027) | (3,839) | — | — | 4,784 |
| Share-based compensation (note 13(c)) | — | — | 11,011 | — | — | — | 11,011 |
| Contributions received from non-controlling interests (notes 3(d)), net of costs | — | — | — | — | — | 29,110 | 29,110 |
| Balance, December 31, 2018 | $ 3,562,418 | $ 184,299 | $ 45,553 | $ (595,259) | $ (19,385) | $ 519,896 | $ 3,697,522 |

## Algonquin Power & Utilities Corp.
## Consolidated Statement of Equity

*(thousands of U.S. dollars)*
For the year ended December 31, 2017

| | Algonquin Power & Utilities Corp. Shareholders | | | | | | |
|---|---|---|---|---|---|---|---|
| | Common shares | Preferred shares | Additional paid-in capital | Accumulated deficit | Accumulated OCI | Non-controlling interests | Total |
| Balance, December 31, 2016 | $ 1,674,591 | $ 184,299 | $ 34,892 | $ (478,343) | $ 17,051 | $ 418,826 | $ 1,851,316 |
| Net earnings (loss) | — | — | — | 149,475 | — | (47,770) | 101,705 |
| Redeemable non-controlling interests not included in equity (note 17) | — | — | — | — | — | 10,358 | 10,358 |
| Other comprehensive income (loss) | — | — | — | — | (19,843) | 27 | (19,816) |
| Dividends declared and distributions to non-controlling interests | — | — | — | (158,064) | — | (3,860) | (161,924) |
| Dividends and issuance of shares under dividend reinvestment plan (note 13(a)(ii)) | 35,873 | — | — | (35,873) | — | — | — |
| Common shares issued pursuant to public offering, net of costs (note 13(a)(i)) | 440,024 | — | — | — | — | — | 440,024 |
| Common shares issued upon conversion of convertible debentures (note 12(h)) | 855,691 | — | — | — | — | — | 855,691 |
| Common shares issued pursuant to share-based awards (note 13(c)) | 15,520 | — | (4,910) | (1,506) | — | — | 9,104 |
| Share-based compensation (note 13 (c)) | — | — | 8,587 | — | — | — | 8,587 |
| Contributions received from non-controlling interests (notes 3(d), 3(g) and 8(f)(ii)), net of costs | — | — | — | — | — | 225,055 | 225,055 |
| Balance, December 31, 2017 | $ 3,021,699 | $ 184,299 | $ 38,569 | $ (524,311) | $ (2,792) | $ 602,636 | $ 3,320,100 |

See accompanying notes to consolidated financial statements

# Algonquin Power & Utilities Corp.
# Consolidated Statements of Cash Flows

| *(thousands of U.S. dollars)* | Year ended December 31 2018 | 2017 |
|---|---|---|
| **Cash provided by (used in):** | | |
| **Operating Activities** | | |
| Net earnings from continuing operations | $ 79,089 | $ 101,705 |
| Adjustments and items not affecting cash: | | |
| Depreciation and amortization | 281,163 | 256,775 |
| Deferred taxes | 42,025 | 65,910 |
| Unrealized (gain) loss on derivative financial instruments | (1,781) | 1,466 |
| Share-based compensation expense | 7,495 | 8,292 |
| Cost of equity funds used for construction purposes | (2,728) | (2,335) |
| Change in value of investments carried at fair value | 137,957 | — |
| Pension and post-employment contributions in excess of expense | (6,354) | (20,687) |
| Distributions received from equity investments, net of income | 5,698 | 2,420 |
| Others | (4,086) | 740 |
| Changes in non-cash operating items (note 22) | (8,126) | (87,719) |
| | 530,352 | 326,567 |
| **Financing Activities** | | |
| Increase in long-term debt | 2,015,533 | 1,386,743 |
| Decrease in long-term debt | (1,699,592) | (2,366,105) |
| Issuance of convertible debentures, net of costs | — | 571,944 |
| Cash dividends on common shares | (166,384) | (127,530) |
| Dividends on preferred shares | (8,027) | (8,020) |
| Contributions from non-controlling interests, related party (note 17) | 305,000 | — |
| Contributions from non-controlling interests (note 17) | 15,250 | 248,229 |
| Production-based cash contributions from non-controlling interest | 13,860 | 7,930 |
| Distributions to non-controlling interests | (9,289) | (3,186) |
| Issuance of common shares, net of costs | 473,911 | 438,810 |
| Proceeds from settlement of derivative assets | — | 36,676 |
| Proceeds from exercise of share options | 4,504 | 9,563 |
| Shares surrendered to fund withholding taxes on exercised share options | (2,088) | (3,310) |
| Increase in other long-term liabilities | 9,403 | 28,010 |
| Decrease in other long-term liabilities | (20,144) | (6,709) |
| | 931,937 | 213,045 |
| **Investing Activities** | | |
| Acquisitions of operating entities | — | (1,519,923) |
| Divestiture of operating entity | — | 83,863 |
| Additions to property, plant and equipment | (466,369) | (565,103) |
| Increase in other assets | (5,912) | (7,239) |
| Receipt of principal on notes receivable | 17,950 | — |
| Increase in long-term investments | (1,005,072) | (63,656) |
| Decrease in long-term investments | 1,158 | |
| Proceeds from sale of long-lived assets | 2,912 | — |
| | (1,455,333) | (2,072,058) |
| Effect of exchange rate differences on cash and restricted cash | (606) | 598 |
| Increase (decrease) in cash, cash equivalents and restricted cash | 6,350 | (1,531,848) |
| Cash, cash equivalents and restricted cash, beginning of year | 59,423 | 1,591,271 |
| Cash, cash equivalents and restricted cash, end of year | $ 65,773 | $ 59,423 |

| **Supplemental disclosure of cash flow information:** | **2018** | **2017** |
|---|---|---|
| Cash paid during the year for interest expense | $ 155,309 | $ 166,773 |
| Cash paid during the year for income taxes | $ 9,652 | $ 8,633 |
| **Non-cash financing and investing activities:** | | |
| Property, plant and equipment acquisitions in accruals | $ 45,154 | $ 112,959 |
| Issuance of common shares under dividend reinvestment plan and share-based compensation plans | $ 65,767 | $ 38,724 |
| Issuance of common shares upon conversion of convertible debentures | $ 468 | $ 846,271 |
| Acquisition of equity investments in exchange for loan receivable and property, plant and equipment | $ 13,092 | $ 5,368 |

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the *Canada Business Corporations Act*. APUC's operations are organized across two primary North American business units consisting of the Liberty Utilities Group and the Liberty Power Group. The Liberty Utilities Group ("Liberty Utilities Group") owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations; the Liberty Power Group ("Liberty Power Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets. APUC also owns a 41.5% equity interest in Atlantica Yield plc ("Atlantica") (NASDAQ: AY), a company that acquires, owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission and water assets.

## 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(m)). Intercompany transactions and balances have been eliminated. Interests in subsidiaries owned by third parties are included in non-controlling interests (note 1(r)).

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets that 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 concentration of assets, 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 acquisition costs.

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

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

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

(d) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, *Regulated Operations* ("ASC 980").

## 1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

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 or liabilities. The impact could be material to the Company’s reported financial condition and results of operations.

The electric, gas and water utilities’ accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (“FERC”), the Regulator 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, deposits to be returned back to customers, and certain requirements related to generation and transmission operations. Cash reserves segregated from APUC’s cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

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

(h) Fuel and natural gas in storage

Fuel and natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents fuel, 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(d)) 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 net realizable value of fuel and 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 net realizable value. Through rate orders and the regulatory environment, capitalized construction jobs are recovered through rate base and repair and maintenance expenses are recovered through a cost of service calculation. Accordingly, the cost usually reflects the net realizable value.

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

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.

| | 2018 | 2017 |
|---|---|---|
| Interest capitalized on non-regulated property | $ 1,434 | $ 4,325 |
| AFUDC capitalized on regulated property: | | |
| Allowance for borrowed funds | 1,684 | 1,297 |
| Allowance for equity funds | 2,728 | 2,335 |
| Total | $ 5,846 | $ 7,957 |

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 12(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.

## 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 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Generation | 3 - 60 | 3 - 60 | 33 | 33 |
| Distribution | 5 - 100 | 5 - 100 | 40 | 40 |
| Equipment | 5 - 43 | 5 - 43 | 10 | 10 |

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

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

(k) Commonly owned facilities

The Company owns undivided interests in three electric generating facilities with ownership interest ranging from 7.52% to 60% with a corresponding share of capacity and generation from the facility used to serve certain of its utility customers. The Company's investment in the undivided interest is recorded as plant in service and recovered through rate base. The Company's share of operating costs are recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

(l) 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.

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.

(m) Variable interest entities

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

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

## 1. Significant accounting policies (continued)

(m) Variable interest entities (continued)

Total net book value of generating assets and long-term debt of these facilities amounts to $59,288 (2017 - $67,398) and $22,263 (2017 - $28,628), respectively. The portion of long-term debt which has recourse to the Company is $nil (2017 - $3,109). The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $17,232 (2017 - $17,508), operating expenses and amortization of $4,634 (2017 - $4,289) and interest expense of $1,258 (2017 - $2,755).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are either accounted for using the equity method or at fair value. 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 equity-method investees in interest, dividend, equity and other income in the consolidated statements of operations. APUC records in the consolidated statements of operations, the fluctuations in the fair value of its investees held at fair value and dividend income when it is declared by the investee.

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

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

(o) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, other post-employment benefit ("OPEB") plans, and supplemental retirement program ("SERP") 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, OPEB and SERP 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. When settlements of the Company's pension plans occur, the Company recognizes associated gains or losses immediately in earnings if the cost of all settlements during the year is greater than the sum of the service cost and interest cost components of the pension plan for the year. The amount recognized is a pro rata portion of the gains and losses in AOCI equal to the percentage reduction in the projected benefit obligation as a result of the settlement. The costs of the Company's pension for employees are expensed over the periods during which employees render service and the service costs are recognized as part of administrative expenses in the consolidated statements of operations.

The components of net periodic benefit cost other than the service cost component are included in pension and post-employment non-service costs in the consolidated statements of operations.

## 1. Significant accounting policies (continued)

(p) 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.

(q) 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; a restricted share unit ("RSU") 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 expenses in the consolidated statements of operations and additional paid-in capital in equity. Additional paid-in capital is reduced as the awards are exercised, and the amount initially recorded in additional paid-in capital is credited to common shares.

(r) 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 ("LLCs") and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units" or "Class A Equity Investors") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLCs and partnership agreements have liquidation rights and priorities that are different from the underlying percentages ownership interests. In those situations, simply applying the percentage ownership interest to GAAP net income in order to determine earnings or losses would not accurately represent the income allocation and cash flow distributions that will ultimately be received by the investors. As such, the share of earnings attributable to the non-controlling interest holders in these entities is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting (note 17).

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

## 1. Significant accounting policies (continued)

(r) Non-controlling interests (continued)

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity and presented as redeemable non-controlling interests 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.

(s) Recognition of revenue

The Company accounts for revenue in accordance with ASC Topic 606, *Revenue from Contracts with Customers*, which was adopted on January 1, 2018 using the modified retrospective method, applied to contracts that are not completed at the date of initial application. Results for 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with the Company's historical accounting under Topic 605. The adoption of the new standard resulted in an adjustment of $2,488 or $1,860 net of taxes to increase opening retained earnings for previously deferred revenue related to the Empire fiber business.

Revenue is recognized when control of the promised goods or services is transferred to the Company's customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for those goods or services.

Refer to note 20, Segmented information for details of revenue disaggregation by business units.

**Liberty Utilities Group revenue**

Liberty Utilities Group revenues consist primarily of the distribution of electricity, natural gas, and water.

Revenue related to utility electricity and natural gas sales and distribution is recognized over time as the energy 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. Unbilled receivables are typically billed within the next month. Some customers elect to pay their bill on an equal monthly plan. As a result, in some months cash is received in advance of the delivery of electricity. Deferred revenue is recorded for that amount. The amount of revenue recognized in the period from the balance of deferred revenue is not significant.

Water reclamation and distribution revenue is recognized over time 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. Unbilled receivables are typically billed within the next month.

The majority of Liberty Utilities Group's contracts have a single performance obligation that represents a promise to transfer to the customer a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The Company's performance obligation is satisfied over time as electricity, natural gas or water is delivered.

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.

## 1. Significant accounting policies (continued)

(s) Recognition of revenue (continued)

**Liberty Utilities Group revenue (continued)**

Revenue for certain of the Company's regulated utilities is subject to alternative revenue programs approved by their respective regulators. Under these programs, the Company charges 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 disclosed as alternative revenue in note 20, Segmented information and is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7). The amount subsequently billed to customers is recorded as a recovery of the regulatory asset.

**Liberty Power Group revenue**

Liberty Power Group's revenue consists primarily of the sale of electricity, capacity, and renewable energy credits.

Revenue related to the sale of electricity is recognized over time as the electricity is delivered. The electricity represents a single performance obligation that represents a promise to transfer to the customer a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer.

Progress towards satisfaction of the single performance obligation is measured using an output method based on units produced and delivered within the production month.

Revenues related to the sale of capacity are recognized over time as the capacity is provided. The nature of the promise to provide capacity is that of a stand-ready obligation. The capacity is generally expressed in monthly volumes and prices. The capacity represents a single performance obligation that represents a promise to transfer to the customer a series of distinct services that are substantially the same and that have the same pattern of transfer to the customer. Progress towards satisfaction of the single performance obligation is measured using an output method based on time elapsed.

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

The majority of Liberty Power Group's contracts with customers are bundled arrangements of multiple performance obligations: electricity, capacity, and RECs.

The Company has elected to apply the invoicing practical expedient to the electricity and capacity in the Liberty Power Group contracts. The Company does not disclose the value of unsatisfied performance obligations for these contracts as revenue is recognized at the amount to which the Company has the right to invoice for services performed.

Revenue is recorded net of sales taxes.

(t) Foreign currency translation

APUC's reporting currency is the U.S. dollar. Within these consolidated financial statements, we denote any amounts denominated in Canadian dollars with "C$" immediately prior to the stated amount.

The Company's Canadian operations are determined to have the Canadian dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in Canadian dollars. The financial statements of these operations are translated into U.S. 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.

## 1. Significant accounting policies (continued)

(u) 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 (note 18). Investment tax credits for our rate regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the properties. Other income tax credits are treated as a reduction to income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

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

(v) Financial instruments and derivatives

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

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

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

## 1. Significant accounting policies (continued)

(v) Financial instruments and derivatives (continued)

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.

(w) 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.

(x) Commitments and contingencies

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

(y) 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 measurement of deferred taxes and 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 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans* as part of the disclosure framework project. This update removed certain disclosure requirements regarding AOCI expected to be recognized in income, related party transactions, and certain sensitivity analyses with respect to health care cost trends. This update also added disclosure requirements around the weighted-average interest crediting rates for cash balance plans and explanations for significant gains or losses in the reporting period. The early adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement* as part of the disclosure framework project. This update removed certain disclosure requirements from Topic 820 including the amount of and reasons for transfers between Level 1 and Level 2 measurements, the policy for timing of transfers between levels, and the valuation processes for Level 3 measurements. This update also clarified disclosure requirements relating to measurement uncertainty, and added disclosure requirements for Level 3 measurements, specifically around the changes in unrealized gains and losses included in other comprehensive income and the range and weighted average of significant unobservable inputs. The early adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-09, *Codification Improvements* to clarify the Codification and correct unintended application of guidance that is not expected to have a significant impact on current accounting practice. The adoption of this ASU had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-03, *Technical Corrections and Improvements to Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* to clarify the Codification and to correct unintended application of the guidance. The Company adopted this pronouncement concurrently with the adoption of ASU 2016-01. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* ("AOCI") to allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The Company early adopted this pronouncement as of January 1, 2018, and as a result, a net amount of $10,625 was reclassified out of AOCI and recorded as an increase to accumulated deficit as at that date.

The FASB issued ASU 2017-09, *Compensation-Stock Compensation (Topic 718): Scope of Modification Accounting* , to provide clarity and reduce both diversity in practice and cost and complexity when applying the guidance in Topic 718, *Compensation-Stock Compensation*, to a change to the terms or conditions of a share-based payment award. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost*, to improve the reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. This update requires the service cost component to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update also only allows the service cost component to be eligible for capitalization when applicable. The Company adopted this guidance effective January 1, 2018. The Company's regulated operations only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences exist. The Company applied the practical expedient for retrospective application on the consolidated statements of operations (note 10).

**2. Recently issued accounting pronouncements (continued)**

(a) Recently adopted accounting pronouncements (continued)

The FASB issued ASU 2017-05, *Other Income—Gains and Losses from the Derecognition of Non-financial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*. The update clarifies the scope of the standard and provides additional guidance on partial sales of non-financial assets. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business* . The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Company follows the pronouncements of this update as of January 1, 2018.

The FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* to eliminate current diversity in practice in the classification and presentation of changes in restricted cash on the statement of cash flows. Prior to the adoption of this update, the Company presented changes in restricted cash as investing activities on the consolidated statement of cash flows.

The FASB issued ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory* . The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments* in order to eliminate current diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The adoption of this update had no impact on the Company's 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 adoption of this update had no significant impact on the Company's consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2018-19: *Codification Improvements to Topic 326, Financial Instruments — Credit Losses* as part of its project to correct unintended application of accounting standards. The amendments clarify that receivables arising from operating leases are not within the scope of ASC 326-20. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with Topic 842, *Leases*. The amendments in this Update are effective the same date as Update 2016-13, which is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company is currently assessing the impact of this Update.

The FASB issued ASU 2018-18, *Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606* to reduce diversity in practice on how entities account for transactions on the basis of different views of the economics of a collaborative arrangement. The Update clarifies that the arrangement should be accounted for under ASC 606 when a participant is a customer in the context of a unit of account, adds unit of account guidance in ASC 808 that is consistent with ASC 606, and precludes the recognition of revenue from a collaborative arrangement with ASC 606 revenue if the participant is not directly related to sales to third parties. The amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within those years. Early adoption is permitted. The Company is currently assessing the impact of this Update.

The FASB issued ASU 2018-17, *Consolidation (Topic 810): Targeted Improvements to Related Party Guidance for Variable Interest Entities* to improve general purpose financial reporting. The Update clarifies that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. The amendments in the Update are effective for fiscal years beginning after December 15, 2019 and interim periods within those fiscal years. The amendments are required to be applied retrospectively with a cumulative-effect adjustment to retained earnings. Early adoption is permitted. The Company is currently assessing the impact of this Update.

## 2. Recently issued accounting pronouncements (continued)

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

The FASB issued ASU 2018-16, *Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate ("*SOFR*") Overnight Index Swap ("*OIS*") Rate as a Benchmark Interest Rate for Hedge Accounting Purposes* to identify a suitable alternative to the U.S. dollar LIBOR that is more firmly based on actual transactions in a robust market. This Update permits the use of the OIS rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes. The amendments in this Update are required to be adopted concurrently with the amendments in Update 2017-12, which is required for all fiscal years beginning after December 15, 2018. The amendments will be adopted prospectively for qualifying new or redesignated hedging relationships entered into after the date of adoption.

The FASB issued ASU 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40*): Customers Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract to provide additional guidance to address diversity in practice. This update aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Therefore, an entity will follow the guidance in Subtopic 350-40 to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. In addition, the capitalized implementation costs are required to be expensed over the term of the hosting arrangement. This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted in any interim period. The amendments can either be applied retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently assessing the impacts of this update.

The FASB issued ASU 2018-07, *Compensation — Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Payment Accounting* to expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from non-employees. This update changes the measurement basis and date of non-employee share-based payment awards and also makes amendments to how to measure non-employee awards with performance conditions. The update is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. No impact on the consolidated financial statements is expected from the adoption of this update.

The FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Company does not expect a significant impact on the consolidated financial statements as a result of the adoption of this update.

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

The FASB issued ASU 2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this Update.

## 2. Recently issued accounting pronouncements (continued)

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

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 FASB issued an amendment to ASC Topic 842 that permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The FASB issued a further update to ASC Topic 842 in ASU 2018-11 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The FASB has also issued further codification and narrow-scope improvements to ASC Topic 842 to correct and clarify specific aspects of the guidance. The standard is effective for fiscal years and interim periods beginning after December 15, 2018.

The Company is in the process of finalizing its assessment of the financial, operational, and business processes impacts of the new lease accounting standard. At this point, the Company expects that the adoption of Topic 842 will not have a material impact on the consolidated financial statements. The Company intends to implement new processes and procedures for the identification, analysis, and measurement of new lease contracts on a prospective basis. A new software solution is being implemented to assist with contract management, information tracking, and measurement as it relates to the new standard. The Company intends to elect the following practical expedients as part of its adoption:

1. "Package of three" practical expedient that permits the Company not to reassess the scope, classification and initial direct costs of its expired and existing leases;
2. Land easements practical expedient that permits the Company not to reassess the accounting for land easements previously not accounted for under ASC 840; and
3. Hindsight practical expedient that allows the Company to use hindsight in determining the lease term for existing contracts.

In addition, the Company will make an accounting policy election to not recognize a lease liability or right-of-use asset on its consolidated balance sheets for short-term leases (lease term less than 12 months).

The Company intends to adopt the lease accounting standard retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment.

## 3. Business acquisitions and development projects

(a) Agreement to acquire Enbridge Gas New Brunswick Limited Partnership

On December 4, 2018, the Company entered into an agreement to acquire Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas"). New Brunswick Gas is a regulated utility that provides natural gas to approximately 12,000 customers and operates approximately 800 km of natural gas distribution pipeline. The total purchase price for the transaction is C$331,000, subject to certain closing adjustments. Closing of the transaction remains subject to regulatory approval and is expected in 2019.

(b) Agreement to acquire St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into an agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate regulated natural gas distribution utility serving customers in northern New York State. The total purchase price for the transaction is $70,000, less total third-party debt of SLG outstanding at closing, subject to certain closing adjustments. Closing of the transaction remains subject to regulatory approval and is expected to occur in 2019.

(c) Approval to acquire the Perris Water Distribution System

On August 10, 2017, the Company's Board of Directors approved the acquisition of two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. The Liberty Utilities Group filed an application requesting approval for the acquisition of the assets of the water utilities with the California Public Utility Commission on May 8, 2018. Final approval is expected in 2019.

(d) Great Bay Solar Facility

The Great Bay Solar Facility consists of a 75 MWac solar powered generating facility in Somerset County, Maryland. As of December 31, 2017, three sites had been fully synchronized with the power grid, while the last site was placed in service in March 2018. Commercial operations as defined by the power purchase agreement was reached for all sites by March 29, 2018.

The Great Bay Solar Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). The Class A partnership units are owned by a third-party tax equity investor who funded $42,750 in 2017 with the remaining amount of $15,250 received in 2018. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

## 3. Business acquisitions and development projects (continued)

(e) Acquisition of Empire

On January 1, 2017, the Company completed the acquisition of Empire, a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

The purchase price of approximately $2,414,000 for the acquisition of Empire consists of a cash payment to Empire shareholders of $34.00 per common share and the assumption of approximately $855,000 of debt. The cash payment was funded with the acquisition facility for an amount of $1,336,440 (note 9(b)), proceeds received from the initial instalment of convertible debentures and existing credit facility. The costs related to the acquisition have been expensed through the consolidated statements of operations.

| | | |
|---|---|---|
| Working capital | $ | 41,292 |
| Property, plant and equipment | | 2,058,867 |
| Goodwill | | 752,418 |
| Regulatory assets | | 236,933 |
| Other assets | | 43,609 |
| Long-term debt | | (907,547) |
| Regulatory liabilities | | (145,594) |
| Pension and other post-employment benefits | | (78,204) |
| Deferred income taxes liability, net | | (418,855) |
| Other liabilities | | (76,532) |
| Total net assets acquired | $ | 1,506,387 |
| Cash and cash equivalents | | 1,742 |
| Total net assets acquired, net of cash and cash equivalents | $ | 1,504,645 |

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

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

Property, plant and equipment, exclusive of computer software, are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Empire's assets is 39 years.

(f) Luning Solar Facility

Luning Utilities (Luning Holdings) LLC (the “Luning Holdings”) is owned by the Calpeco Electric System. The 50 MWac solar generating facility is located in Mineral County, Nevada. During 2016, a tax equity agreement was executed. The Class A partnership units are owned by a third-party tax equity investor who funded $7,826 as of December 31, 2016 and $31,212 on February 17, 2017. With its interest, the tax equity investor will receive the majority of the tax attributes associated with the Luning Solar project. During a six-month period in year 2022, the tax investor has the right to withdraw from Luning Holdings 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 (note 17). Redemption is not considered probable as of December 31, 2018.

On February 15, 2017, as the Luning Solar Facility achieved commercial operation, Luning Holdings obtained control for a total purchase price of $110,856.

## 3. Business acquisitions and development projects (continued)

(f) Luning Solar Facility (continued)

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

| | |
|---|---|
| Working capital | $ 152 |
| Property, plant and equipment | 110,857 |
| Asset retirement obligation | (546) |
| Non-controlling interest (tax equity) | (38,633) |
| Total net assets acquired | $ 71,830 |

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

(g) Bakersfield II Solar Facility

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

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

## 4. Accounts receivable

Accounts receivable as of December 31, 2018 include unbilled revenue of $79,742 (2017 - $78,289) from the Company's regulated utilities. Accounts receivable as of December 31, 2018 are presented net of allowance for doubtful accounts of $5,281 (2017 - $5,555).

## 5. Property, plant and equipment

Property, plant and equipment consist of the following:

**2018**

| | Cost | Accumulated depreciation | Net book value |
|---|---|---|---|
| Generation | $ 2,470,279 | $ 450,230 | $ 2,020,049 |
| Distribution | 4,455,935 | 521,236 | 3,934,699 |
| Land | 73,773 | — | 73,773 |
| Equipment and other | 88,757 | 41,295 | 47,462 |
| Construction in progress | | | |
| Generation | 104,996 | — | 104,996 |
| Distribution | 212,579 | — | 212,579 |
| | $ 7,406,319 | $ 1,012,761 | $ 6,393,558 |

## 5. Property, plant and equipment (continued)

**2017**

| | Cost | Accumulated depreciation | Net book value |
|---|---|---|---|
| Generation | $ 2,382,279 | $ 394,509 | $ 1,987,770 |
| Distribution | 4,205,823 | 388,859 | 3,816,964 |
| Land | 71,689 | — | 71,689 |
| Equipment and other | 91,233 | 37,104 | 54,129 |
| Construction in progress | | | |
| Generation | 209,979 | — | 209,979 |
| Distribution | 164,366 | — | 164,366 |
| | $ 7,125,369 | $ 820,472 | $ 6,304,897 |

Generation assets include cost of $104,107 (2017 - $113,822) and accumulated depreciation of $34,916 (2017 - $34,908) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $1,987 (2017 - $1,633).

Distribution assets include cost of $1,383,960 (2017 - $1,341,716) and accumulated depreciation of $69,960 (2017 - $28,809) related to regulated generation and transmission assets. Distribution assets include cost of $546,332 (2017 - $493,570) and accumulated depreciation of $42,476 (2017 - $8,578) related to commonly owned facilities (note 1(k)). Total expenditures for the year ended December 31, 2018 were $75.427 (2017 - $79.657). Distribution assets include cost of $3,076 (2017 - $3,076) and accumulated depreciation of $669 (2017 - $336) related to assets under capital lease. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

For the year ended December 31, 2018, contributions received in aid of construction of $6,057 (2017 - $12,742) have been credited to the cost of the assets.

## 6. Intangible assets and goodwill

Intangible assets consist of the following:

| 2018 | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Power sales contracts | $ 60,775 | $ 36,063 | $ 24,712 |
| Customer relationships | 26,795 | 9,476 | 17,319 |
| Interconnection agreements | 13,847 | 884 | 12,963 |
| | $ 101,417 | $ 46,423 | $ 54,994 |

| 2017 | Cost | | Accumulated amortization | Net book value |
|---|---|---|---|---|
| Power sales contracts | $ 56,540 | | $ 36,878 | $ 19,662 |
| Customer relationships | 26,799 | | 8,836 | 17,963 |
| Interconnection agreements | 14,181 | — | 703 | 13,478 |
| | $ 97,520 | | $ 46,417 | $ 51,103 |

Estimated amortization expense for intangible assets for the next year is $2,093, $2,265 in year two, $2,430 in year three, $2,400 in year four and $1,820 in year five.

## 6. Intangible assets and goodwill (continued)

All goodwill pertains to the Liberty Utilities Group. Changes in goodwill are as follows:

| | | |
|---|---|---|
| Balance, January 1, 2017 | $ | 228,377 |
| Business acquisitions | | 752,418 |
| Divestiture of operating entity (note 21(a)) | | (26,513) |
| Balance, December 31, 2018 and 2017 | $ | 954,282 |

## 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.

On January 1, 2017, the Company completed the acquisition of Empire, an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire also provides regulated water utility distribution services to three towns in Missouri. The Empire District Gas Company, a wholly owned subsidiary, is engaged in the distribution of natural gas in Missouri. These businesses are subject to regulation by the Missouri Public Service Commission, the State Corporation Commission of the State of Kansas, the Corporation Commission of Oklahoma, the Arkansas Public Service Commission and the Federal Energy Regulatory Commission. In general, the commissions set rates at a level that allows the utilities to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

## 7. Regulatory matters (continued)

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. The following regulatory proceedings were recently completed:

| Utility | State | Regulatory Proceeding Type | Annual Revenue Increase $'000 | Effective Date |
|---|---|---|---|---|
| Empire Electric System | Missouri | Tax Reform docket | $ (17,837) | Prospective decrease in annual revenue effective August 30, 2018 due to the reduction of the U.S. federal corporate income tax rate. |
| EnergyNorth Gas System | New Hampshire | General Rate Review | $ 10,711 | Effective May 1, 2018. The regulator also approved a one-time recoupment of $1,326 for the difference between the final rates and temporary rates granted on July 1, 2017. In November 2018, EnergyNorth received an order for rehearing clarifying the implementation of the decoupling mechanism that was approved and resolving the impacts of tax reform through the rehearing. The net result was a one-time decrease to the recoupment of $280. |
| Missouri Gas System | Missouri | General Rate Review | $ 4,600 | Effective July 1, 2018 |
| Peach State Gas System | Georgia | GRAM | $ 2,367 | Effective February 1, 2019 |
| New England Natural Gas System | Massachusetts | Gas System Enhancement Plan | $ 3,676 | Effective May 1, 2018 |
| New England Gas System | Massachusetts | GRC | $ 8,300 | $7,800 effective March 1, 2016<br>$500 effective March 1, 2017 |
| Calpeco Electric System | California | Post-Test Year Adjustment Mechanism | $ 2,175 | January 1, 2018 |
| Midstates Gas System | Illinois | GRC | $ 2,200 | June 7, 2017 |
| Various | Various | Various | $ 3,048 | Other rate reviews closed:<br>Missouri Water ($1,015), and Litchfield Park Water & Sewer ($617), Park Water 2018 increase ($1,531), Georgia 2018 Gas Rate Adjustment Mechanism (-$115) |

## 7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

| | 2018 | 2017 |
|---|---|---|
| **Regulatory assets** | | |
| Environmental remediation (a) | $ 82,295 | $ 82,711 |
| Pension and post-employment benefits (b) | 125,959 | 105,712 |
| Debt premium (c) | 48,847 | 57,406 |
| Fuel and commodity costs adjustments (d) | 26,310 | 34,525 |
| Rate adjustment mechanism (e) | 36,484 | 35,813 |
| Clean Energy and other customer programs (f) | 22,269 | 20,582 |
| Deferred construction costs (g) | 13,986 | 14,344 |
| Asset retirement (h) | 21,048 | 16,080 |
| Income taxes (i) | 34,822 | 36,546 |
| Rate review costs (j) | 7,990 | 9,295 |
| Other | 30,464 | 28,512 |
| Total regulatory assets | $ 450,474 | $ 441,526 |
| Less: current regulatory assets | (59,037) | (66,567) |
| Non-current regulatory assets | $ 391,437 | $ 374,959 |
| **Regulatory liabilities** | | |
| Income taxes (i) | $ 323,384 | $ 321,138 |
| Cost of removal (k) | 193,564 | 184,188 |
| Rate base offset (l) | 10,900 | 13,214 |
| Fuel and commodity costs adjustments (d) | 23,517 | 23,543 |
| Deferred compensation received in relation to lost production (m) | 6,897 | 9,398 |
| Deferred construction costs - fuel related (g) | 7,258 | 7,418 |
| Pension and post-employment benefits (b) | 877 | 10,082 |
| Other | 12,195 | 7,143 |
| Total regulatory liabilities | $ 578,592 | $ 576,124 |
| Less: current regulatory liabilities | (39,005) | (37,687) |
| Non-current regulatory liabilities | $ 539,587 | $ 538,437 |

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 12(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. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 *Compensation Non-retirement Post-employment Benefits* and ASC 715 *Compensation Retirement Benefits* before the transfer to regulatory asset occurred. The annual movements in AOCI for Empire's pension and OPEB plans (note 10(a)) are also reclassified to regulatory accounts since it is probable the unfunded amount of these plans will be afforded rate recovery. Finally, the regulators have also approved tracking accounts for a number of the utilities. The amounts recorded in these accounts occur when actual expenses differs from those adopted and recovery or refunds are expected to occur in future periods.

## 7. Regulatory matters (continued)

(c) Debt premium

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

(d) Fuel and commodity costs adjustments

The revenue from the utilities includes a component which is designed to recover the cost of electricity and natural gas through rates charged to customers. To the extent actual costs of power or natural gas purchased differ from power or natural gas costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of electricity and natural gas in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 23(b)(i)) are recoverable through the commodity costs adjustment.

(e) Rate adjustment mechanism

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

(f) Clean Energy and other customer programs

The regulatory asset for Clean Energy and customer programs includes initiatives related to solar rebate applications processed and resulting rebate-related costs. The amount also includes other energy efficiency programs.

(g) Deferred construction costs

Deferred construction costs reflect deferred construction costs and fuel related costs of specific generating facilities of Empire. These amounts are being recovered over the life of the plants.

(h) Asset retirement

The costs of retirement of assets are expected to be recovered through rates as well as the on-going liability accretion and asset depreciation expense.

(i) Income taxes

The income taxes regulatory assets and liabilities represent income taxes recoverable through future revenues required to fund flow-through deferred income tax liabilities and amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates.

On June 1, 2018, the State of Missouri enacted legislation that, effective for tax years beginning on or after January 1, 2020, reduces the corporate income tax rate from 6.25% to 4%, among other legislative changes. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $15,586.

The Tax Cuts and Jobs Act (the “Tax Act”) was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. A reduction of regulatory asset and an increase to regulatory liability was recorded in 2017 for excess deferred taxes probable of being refunded to customers of $327,947.

## 7. Regulatory matters (continued)

(i) Income taxes (continued)

As a result of the Tax Act enacted in 2017, regulators in the states where Liberty Utilities Group operates are contemplating the ratemaking implications of the reduction of federal tax rates from the legacy 35% tax rate and the new 21% federal statutory income tax rate effective January 2018. The Company is working with the regulators to identify the most appropriate way in each jurisdiction to address the impact of the Tax Act on cost of service based rates. As at December 31, 2018, the impact on regulated liability on account of ordered or probable orders related to the Tax Act was immaterial.

(j) Rate review costs

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

(k) 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.

(l) Rate base offset

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

(m) Deferred compensation received in relation to lost production

The regulatory liability for deferred compensation received from lost production represents Empire's refund from Southwest Power Administration for lost revenues at one of its generating facilities. These costs are being amortized over the period approved by state regulators.

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

## 8. Long-term investments

Long-term investments consist of the following:

| | 2018 | 2017 |
|---|---|---|
| **Long-term investment in Atlantica carried at fair value (a)** | $ 814,530 | $ — |
| **Notes receivable from equity investees (e)** | $ 101,416 | $ 30,060 |
| **Other long-term investments** | | |
| **Equity-method investees** | | |
| AAGES (b) | 2,622 | — |
| Red Lily I Wind Facility (c) | 15,705 | 18,174 |
| Amherst Island Wind Project (d) | 7,655 | 8,921 |
| Other | 4,510 | 5,172 |
| | $ 30,492 | $ 32,267 |
| **Other investments** | 3,870 | 5,004 |
| **Other long-term investments** | 34,362 | 37,271 |
| Less: current portion | (1,407) | — |
| | $ 32,955 | $ 37,271 |

Dividend income of $41,079 (2017 - $1,167) and equity loss of $1,609 (2017 - income $2,742) are included in Interest, dividend, equity and other income on the consolidated statements of operations.

## 8. Long-term investments (continued)

(a) Investment in Atlantica

On March 9, 2018, APUC purchased from Abengoa S.A. ("Abengoa") a 25% equity interest in Atlantica for a purchase price of $607,567, based on a price of $24.25 per ordinary share of Atlantica plus a contingent payment of up to $0.60 per-share payable two years after closing, subject to certain conditions. On November 27, 2018, APUC purchased from Abengoa an additional 16.5% equity interest in Atlantica for a purchase price of $345,000, based on a price of $20.90 per ordinary share of Atlantica comprised of a payment of approximately $305,000 drawn from the Company's credit facility for payment on closing and a holdback of $40,000 payable at a later date, subject to certain conditions. The Company transferred the Atlantica shares to AAGES (AY Holdings) B.V. ("AY Holdings"), a new entity controlled and consolidated by APUC. The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in Atlantica, with changes in fair value reflected in the consolidated statements of operations. The difference between the purchase price and the value of the Atlantica shares based on the NASDAQ share price on the acquisition dates resulted in a combined immediate fair value loss of $139,864. A fair value gain of $1,907 was recorded for the period from acquisition to December 31, 2018 resulting in a net loss on fair value for the year of $137,957.

The Company also recorded dividend income of $39,263 from the Atlantica shares during the period from acquisition to December 31, 2018.

On November 28, 2018, Abengoa-Algonquin Global Energy Solutions B.V. ("AAGES B.V.") obtained a three year secured credit facility in the amount of $306,500 and subscribed to a preference share ownership interest in AY Holdings. The subscription proceeds were distributed by AY Holdings to the Company and used by the Company to repay the $305,000 drawn under the credit facility. The AAGES B.V. secured credit facility is collateralized through a pledge of the Atlantica shares held by AY Holdings. A collateral shortfall would occur if the net obligation as defined in the agreement would equal or exceed 50% of the market value of the Atlantica shares in which case the lenders would have the right to sell Atlantica stock to eliminate the collateral shortfall. APUC reflects the preference share ownership issued by AY Holdings as redeemable non-controlling interest (note 17).

(b) Investment in AAGES

APUC and Abengoa created AAGES B.V., AAGES Development Canada Inc. and AAGES Development Spain (collectively, the "AAGES entities") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Each partner initially contributed $5,000 to the AAGES entities. AAGES Development Canada Inc. and AAGES Development Spain are considered a VIE due to the level of equity at risk. The Company is not considered the primary beneficiary of AAGES Development Canada Inc. and AAGES Development Spain as the two partners have joint control and all decisions must be unanimous. As such, the Company is accounting for its investment in the joint ventures under the equity method. The AAGES entities contributed equity loss of $3,005 to the Company's consolidated financial results for the year ended December 31, 2018.

As of December 31, 2018, the Company's maximum exposure to loss of $7,509 related to AAGES Development Canada Inc. and AAGES Development Spain is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(e).

(c) Red Lily I Wind Facility

The Red Lily I Wind Facility (the "Partnership") is a 26.4 MW wind energy facility located in southeastern Saskatchewan. The Company owns a 75% equity interest in the Partnership.

Due to certain participating rights being held by the minority investor, the decisions which most significantly impact the economic performance of the Red Lily I Wind Facility require unanimous consent. As such, APUC is deemed, under U.S. GAAP, to not have control over the Partnership. As APUC exercises significant influence over operating and financial policies of the Red Lily I Wind Facility, the Company accounts for the Partnership using the equity method. The Red Lily I Wind Facility contributed equity income of $1,637 (2017 - $2,139) to the Company's consolidated financial results for the year ended December 31, 2018.

## 8. Long-term investments (continued)

(d) Amherst Island Wind Project

APUC has a 50% interest in Windlectric Inc. ("Windlectric") which owns a 74.1 MW wind generating facility ("Amherst Island Wind Facility") in the Province of Ontario. Construction was completed during the second quarter of 2018 and sale of power under the power purchase agreement has started. Subsequent to year-end, the Company exercised its option to acquire the remaining common shares at a pre-agreed price. The acquisition is subject to regulatory approval expected to be obtained in 2019.

Windlectric is considered a VIE due to the level of equity at risk. The Company is not considered the primary beneficiary of Windlectric as the two shareholders have joint control and all decisions must be unanimous. As such, the Company accounts for its investment in the joint venture under the equity method. The interest capitalized during the year ended December 31, 2018 to the investment while the Amherst Island Wind Facility was under construction amounts to $739 (2017 - $1,115).

As at December 31, 2018, the net book value of property, plant and equipment of the joint venture was $308,825 while the third-party construction debt was $190,910 (2017 - $106,628). Windlectric contributed equity loss of $1,714 (2017 - nil) to the Company's consolidated financial results for the year ended December 31, 2018.

As of December 31, 2018, the Company's maximum exposure to loss of $192,052 is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(e). Subsequent to year-end, the joint venture borrowed from the Company to repay in full the third-party construction debt.

(e) Development loans receivable from equity investees

The Company entered into committed loan and credit support facilities with some of its equity investees. During construction, the Company is obligated to provide 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 equity investees' wind projects.

As at December 31, 2018, the Company has a loan and credit support facility with Windlectric of $96,477 (2017 - $30,060). The loan to Windlectric bears interest at an annual rate of 10% on outstanding principal amount and matures on December 31, 2019.

The letters of credit are charged an annual fee of 2% on their stated amount. As of December 31, 2018, the following credit support was outstanding on behalf of Windlectric: letters of credit and guarantees of obligations to the utilities under the power purchase agreement; a guarantee of the obligations under the wind turbine, transmission line, transformer, and other supply agreements; and, a guarantee of the obligations under the engineering, procurement, and construction management agreements. The value of the guarantee obligations is recognized under other long-term liabilities and as at December 31, 2018 is valued at $1,637 (2017 - $1,952) using a probability weighted discounted cash flow (level 3). The Company recognized interest income of $6,144 on the advances and credit support from the day Amherst Island Wind Facility achieved commercial operations to December 31, 2018.

As at December 31, 2018, the Company has a balance receivable from the AAGES entities of $4,940. As at December 31, 2018, the Company has issued $3,750 in letters of credit on behalf of AAGES. Subsequent to year-end, $1,750 was repaid under this credit support facility.

Following acquisition of control of Deerfield SponsorCo (note 8(f)(ii)), amounts advanced to the wind facility are eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in OCI from the date of acquisition.

## 8. Long-term investments (continued)

(f) Other transactions

i. Wataynikaneyap Power Transmission Project

Subsequent to year-end, APUC acquired a 9.8% ownership interest in the Wataynikaneyap Power Transmission Project, a transmission project that involves the development, construction and operation of a 1,800 km transmission line in Northwestern Ontario.

ii. Deerfield Wind Facility

The Company had a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 149 MW construction-stage wind development project ("Deerfield Wind Project") in the State of Michigan. On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo and obtained control of the facility.

The Company accounted for the business combination using the acquisition method of accounting which requires that the fair value of assets acquired and liabilities assumed in the subsidiary be recognized on the consolidated balance sheet as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(e)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of $nil was recorded on acquisition.

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

| | | |
|---|---|---|
| Working capital | $ | (10,808) |
| Property, plant and equipment | | 328,371 |
| Construction loan | | (261,952) |
| Asset retirement obligation | | (2,092) |
| Deferred revenue | | (1,156) |
| Deferred tax liability | | (1,470) |
| Net assets acquired | $ | 50,893 |
| Cash and cash equivalents | $ | 3,107 |
| Net assets acquired, net of cash and cash equivalents | $ | 47,786 |

On May 10, 2017, tax equity funding of $166,595 was received.

## 9. Long-term debt

Long-term debt consists of the following

| Borrowing type | Weighted average coupon | Maturity | Par value | 2018 | 2017 |
|---|---|---|---|---|---|
| Senior unsecured revolving credit facilities (a) | — | 2019-2023 | N/A | $ 97,000 | $ 51,827 |
| Senior unsecured bank credit facilities (b) | — | 2019 | N/A | 321,807 | 134,988 |
| Commercial paper (a) | — | 2023 | N/A | 6,000 | 5,576 |
| **U.S. dollar borrowings** | | | | | |
| Senior unsecured notes (c) | 4.09% | 2020-2047 | $ 1,225,000 | 1,218,680 | 1,217,797 |
| Senior unsecured utility notes (d) | 5.99% | 2020-2035 | $ 222,000 | 240,161 | 246,560 |
| Senior secured utility bonds (e) | 4.75% | 2020-2044 | $ 662,500 | 676,697 | 772,871 |
| Subordinated unsecured notes (f) | 6.88% | 2078 | $ 287,500 | 278,771 | — |
| **Canadian dollar borrowings** | | | | | |
| Senior unsecured notes (g) | 4.43% | 2020-2027 | C$ 650,669 | 474,764 | 623,223 |
| Senior secured project notes | 10.25% | 2020-2027 | C$ 31,310 | 22,915 | 26,709 |
| | | | | $ 3,336,795 | $ 3,079,551 |
| Less: current portion | | | | (13,048) | (12,364) |
| | | | | $ 3,323,747 | $ 3,067,187 |

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

Short-term obligations of $321,807 that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

Recent financing activities:

(a) Senior unsecured revolving credit facilities

On September 20, 2017, the Company amended the terms of its C$65,000 senior unsecured revolving bank credit facility to increase the commitments to C$165,000 and, on November 16, 2018, the Company extended the maturity from November 19, 2018 to November 19, 2019.

On February 23, 2018, the Liberty Utilities Group increased commitments under its credit facility to $500,000 and extended the maturity to February 23, 2023. Concurrent with this amendment, the Liberty Utilities Group closed Empire's credit facility. Liberty Utilities' credit facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire.

On October 6, 2017, the Liberty Power Group amended the terms of its C$350,000 senior unsecured revolving bank credit facility to increase the commitments to $500,000 and extended the maturity from July 31, 2019 to October 6, 2022. The Liberty Power Group extended the maturity of its senior unsecured revolving bank credit facility from October 6, 2022 to October 6, 2023. On February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to $200,000 and extended the maturity to January 31, 2021.

## 9. Long-term debt (continued)

(b) Senior unsecured bank credit facilities

On December 21, 2017, the Company entered into a $600,000 term credit facility with two Canadian banks maturing on December 21, 2018. On March 7, 2018, the Company drew $600,000 under this facility. On December 19, 2018, the Company extended the maturity of this facility to June 21, 2019. The balance drawn as at December 31, 2018 is $186,807.

On December 30, 2016, in connection with the acquisition of Empire (note 3(e)), the Company drew $1,336,440 from its Acquisition Facility. Following receipt of the Final Instalment from the convertible debentures on February 7, 2017 (note 12(h)) and the senior notes financing on March 24, 2017 (note 9(d)), the Company fully repaid the Acquisition Facility.

As at December 31, 2018, the Company had drawn $135,000 on its Corporate Term Credit Facility which matures on July 5, 2019.

(c) Senior unsecured notes

On March 24, 2017, the Liberty Utilities Group's debt financing entity issued $750,000 senior unsecured notes in six tranches. The proceeds were applied to repay the Acquisition Facility (note 9(b)) and other existing indebtedness. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of this financing, the Liberty Utilities Group had entered into forward contracts to lock in the underlying U.S. Treasury interest rates. Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group will be approximately 3.6%.

(d) Senior unsecured utility notes

On January 1, 2017, in connection with the acquisition of Empire (note 3(e)), the Company assumed $102,000 in unsecured utility notes. The notes consist of two tranches, with maturities in 2033 and 2035 with coupons at 6.7% and 5.8%.

(e) Senior secured utility bonds

On January 1, 2017 in connection with the acquisition of Empire (note 3(e)), the Company assumed $733,000 in secured utility bonds. The bonds are secured by a first mortgage indenture and consist of ten tranches with maturities ranging between 2018 and 2044 with coupons ranging from 3.58% to 6.82%. On June 1, 2018, the Company repaid, upon its maturity, a $90,000 secured utility note.

In June 2017, outstanding bonds payable for the Park Water Systems in the amount of $63,000 were repaid using proceeds from the Mountain Water condemnation discussed in note 21(a).

(f) Subordinated unsecured notes

On October 17, 2018, the Company completed the issuance of $287,500 unsecured, 6.875% fixed-to-floating subordinated notes (“subordinated notes”) maturing on October 17, 2078. The subordinated notes are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "AQNA". Beginning on October 17, 2023, and on every quarter thereafter that the subordinated notes are outstanding (the "interest reset date") until October 17, 2028, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 3.677%, payable in arrears. Beginning on October 17, 2028, and on every interest reset date until October 17, 2043, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 3.927%, payable in arrears. Beginning on October 17, 2043, and on every interest reset date until October 17, 2078, the subordinated notes will be rest at an interest rate of the three-month LIBOR plus 4.677%, payable in arrears.

The Company may elect, at its sole option, to defer the interest payable on the subordinated notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after October 17, 2023, the Company may, at its option, redeem the subordinated notes, at a redemption price equal to 100% of the principal amount, together with accrued and unpaid interest.

## 9. Long-term debt (continued)

(f) Canadian dollar senior unsecured notes

Subsequent to year-end, the Liberty Power Group issued C$300,000 senior unsecured notes bearing interest at 4.60% with a maturity date of January 29, 2029. The notes were sold at a price of C$99.952 per C$100.00 principal amount. Concurrent with the financing, the Liberty Power Group unwound and settled the related forward-starting interest rate swap on a notional bond of C$135,000 (note 23(b)(ii)).

On July 25, 2018, the Company repaid, upon its maturity, a C$135,000 unsecured note.

On January 17, 2017, the Liberty Power Group issued C$300,000 senior unsecured notes bearing interest at 4.09% with a maturity date of February 17, 2027. The notes were sold at a price of C$99.929 per C$100.00 principal amount.

As of December 31, 2018, the Company had accrued $33,822 in interest expense (2017 - $33,064). Interest expense on the long-term debt in 2018 was $150,262 (2017 - $142,791).

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

| 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter | Total |
|---|---|---|---|---|---|---|
| $ 334,855 | $ 308,917 | $ 111,880 | $ 343,737 | $ 481,859 | $ 1,740,471 | $ 3,321,719 |

## 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 2018 were $8,446 (2017 - $7,232).

In conjunction with the utility acquisitions, the Company assumes defined benefit pension, supplemental executive retirement plans 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.

## 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 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation, beginning of year | $ 523,743 | $ 247,246 | $ 176,975 | $ 61,888 |
| Projected benefit obligation assumed from business combination | — | 256,486 | — | 97,761 |
| Service cost | 15,481 | 14,747 | 5,791 | 4,838 |
| Interest cost | 18,717 | 20,191 | 6,727 | 6,642 |
| Actuarial (gain) loss | (29,845) | 35,696 | (14,800) | 10,263 |
| Contributions from retirees | — | — | 1,920 | 1,821 |
| Gain on curtailment | (1,875) | (849) | — | (4) |
| Benefits paid | (49,429) | (49,774) | (8,288) | (6,234) |
| Projected benefit obligation, end of year | $ 476,792 | $ 523,743 | $ 168,325 | $ 176,975 |
| **Change in plan assets** | | | | |
| Fair value of plan assets, beginning of year | 403,945 | 176,040 | 130,487 | 21,701 |
| Plan assets acquired in business combination | — | 184,510 | — | 91,532 |
| Actual return on plan assets | (36,987) | 63,250 | (10,603) | 19,733 |
| Employer contributions | 21,570 | 29,919 | 2,068 | 2,068 |
| Benefits paid | (49,429) | (49,774) | (6,410) | (4,547) |
| Fair value of plan assets, end of year | $ 339,099 | $ 403,945 | $ 115,542 | $ 130,487 |
| Unfunded status | $ (137,693) | $ (119,798) | $ (52,783) | $ (46,488) |
| Amounts recognized in the consolidated balance sheets consists of: | | | | |
| Non-current assets | — | — | 3,161 | 3,936 |
| Current liabilities | (872) | (861) | (850) | (1,172) |
| Non-current liabilities | (136,821) | (118,937) | (55,094) | (49,252) |
| Net amount recognized | $ (137,693) | $ (119,798) | $ (52,783) | $ (46,488) |

The accumulated benefit obligation for the pension plans was $439,458 and $490,108 as of December 31, 2018 and 2017, respectively.

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

(a) Net pension and OPEB obligation (continued)

Information for pension and OPEB plans with an accumulated benefit obligation in excess of plan assets:

| | Pension | | OPEB | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Accumulated benefit obligation | 439,458 | 462,943 | 163,375 | 171,175 |
| Fair value of plan assets | 339,099 | 376,276 | 107,430 | 121,561 |

Information for pension and OPEB plans with a projected benefit obligation in excess of plan assets:

| | Pension | | OPEB | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Projected benefit obligation | 476,791 | 523,743 | 163,375 | 171,175 |
| Fair value of plan assets | 339,099 | 403,945 | 107,430 | 121,561 |

On June 22, 2017, all Mountain Water employees were terminated as a result of the condemnation of the Mountain Water assets to the City of Missoula (note 21(a)). The pension and OPEB obligations of these employees remain with the Company. The assets and projected benefit obligations of the plans were revalued at June 30, 2017 and resulted in an actuarial gain of $2,354 recorded in OCI and a curtailment gain of $853 recorded against the loss on long-lived assets.

In 2018, the Company permanently froze the accrual of benefits for participants in Park Water's existing pension plan. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The plan amendments resulted in an decrease to the projected benefit obligation of $1,875 which is recorded as a prior service credit in OCI.

**Change in AOCI (before tax)**

| | Pension | | OPEB | |
|---|---|---|---|---|
| | Actuarial losses (gains) | Past service gains | Actuarial losses (gains) | Past service gains |
| Balance, January 1, 2017 | $ 27,572 | $ (5,617) | $ (3,861) | $ (732) |
| Additions to AOCI | (2,652) | — | (3,066) | — |
| Reclassification to regulatory accounts (note 7(b)) | 1,136 | — | 3,515 | — |
| Amortization in current period | (928) | 622 | 230 | 262 |
| Balance, December 31, 2017 | $ 25,128 | $ (4,995) | $ (3,182) | $ (470) |
| Additions to AOCI | 34,916 | (1,875) | 3,254 | — |
| Reclassification to regulatory accounts (note 7(b)) | (22,166) | — | (14,232) | — |
| Amortization in current period | (1,074) | 649 | 272 | 262 |
| Gain (loss) on plan settlements | (2,547) | — | — | — |
| Balance, December 31, 2018 | $ 34,257 | $ (6,221) | $ (13,888) | $ (208) |

The movements in AOCI for Empire's pension and OPEB plans are reclassified to regulatory accounts since it is probable the unfunded amount of these plans will be afforded rate recovery (note 7(b)).

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

(b) Assumptions

Weighted average assumptions used to determine net benefit obligation for 2018 and 2017 were as follows:

| | Pension benefits | | OPEB | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Discount rate | 4.19% | 3.43% | 4.26% | 3.60% |
| Interest crediting rate (for cash balance plans) | 4.43% | 4.50% | N/A | N/A |
| Rate of compensation increase | 4.00% | 3.00% | N/A | N/A |
| Health care cost trend rate | | | | |
| Before age 65 | | | 6.25% | 6.25% |
| Age 65 and after | | | 6.25% | 6.25% |
| Assumed ultimate medical inflation rate | | | 4.75% | 4.75% |
| Year in which ultimate rate is reached | | | 2031 | 2024 |

The mortality assumption for December 31, 2018 was updated to the projected generationally scale MP-2018, adjusted to reflect the ultimate improvement rates in the 2018 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.

Weighted average assumptions used to determine net benefit cost for 2018 and 2017 were as follows:

| | Pension benefits | | OPEB | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Discount rate | 3.57% | 4.01% | 3.60% | 4.12% |
| Expected return on assets | 7.13% | 7.01% | 6.52% | 3.88% |
| Rate of compensation increase | 3.00% | 3.00% | N/A | N/A |
| Health care cost trend rate | | | | |
| Before Age 65 | | | 6.25% | 6.25% |
| Age 65 and after | | | 6.25% | 6.25% |
| Assumed Ultimate Medical Inflation Rate | | | 4.75% | 4.75% |
| Year in which Ultimate Rate is reached | | | 2024 | 2023 |

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

(c) Benefit costs

The following table lists the components of net benefit cost 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 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Service cost | $ 15,481 | $ 14,747 | $ 5,791 | $ 4,838 |
| Non-service costs | | | | |
| Interest cost | 18,717 | 20,191 | 6,727 | 6,642 |
| Expected return on plan assets | (27,820) | (24,842) | (7,451) | (6,404) |
| Amortization of net actuarial loss (gain) | 1,119 | 1,140 | (272) | (230) |
| Amortization of prior service credits | (649) | (622) | (262) | (262) |
| Amortization of regulatory assets/liability | 9,823 | 13,031 | 3,982 | 391 |
| Net benefit cost | $ 16,671 | $ 23,645 | $ 8,515 | $ 4,975 |

As a result of the adoption of ASU 2017-07 (note 2(a)), the service cost components of pension plans and OPEB are shown as part of operating expenses within operating income in the consolidated statements of operations. The remaining components of net benefit cost are considered non-service costs and have been included outside of operating income in pension and post-employment non-service costs in the consolidated statements of operations. The Company applied the practical expedient for retrospective application on the consolidated statements of operations and as such, the $9,035 of non-service costs for the twelve months ended December 31, 2017 has been reclassified from administrative expenses to pension and post-employment non-service costs.

(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 | 69% | 49% - 78% |
| Debt securities | 31% | 22% - 51% |
| | 100% | |

The fair values of investments as of December 31, 2018, by asset category, are as follows:

| Asset Class | Level 1 | Percentage |
|---|---|---|
| Equity securities | $ 338,946 | 75% |
| Debt securities | 115,695 | 25% |
| Other | — | —% |
| | $ 454,641 | 100% |

As of December 31, 2018, the funds do not hold any material investments in APUC.

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

(e) Cash flows

The Company expects to contribute $20,137 to its pension plans and $5,562 to its post-employment benefit plans in 2019.

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

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024—2028 |
|---|---|---|---|---|---|---|
| Pension plan | $ 31,101 | $ 29,366 | $ 32,508 | $ 33,415 | $ 35,111 | $ 183,338 |
| OPEB | 6,077 | 6,686 | 7,172 | 7,731 | 8,241 | 47,119 |

## 11. Other assets

Other assets consist of the following:

| | 2018 | 2017 |
|---|---|---|
| Income tax recoverable | $ 1,961 | $ 5,967 |
| Deferred financing costs | 4,449 | 3,546 |
| Restricted cash | 18,954 | 15,939 |
| Other | 9,335 | 10,811 |
| | 34,699 | 36,263 |
| Less: current portion | (6,115) | (7,110) |
| | $ 28,584 | $ 29,153 |

## 12. Other long-term liabilities

Other long-term liabilities consist of the following:

| | 2018 | 2017 |
|---|---|---|
| Advances in aid of construction (a) | $ 63,703 | $ 62,683 |
| Environmental remediation obligation (b) | 55,621 | 54,322 |
| Asset retirement obligations (c) | 43,291 | 44,166 |
| Customer deposits (d) | 29,974 | 28,529 |
| Unamortized investment tax credits (e) | 17,491 | 17,839 |
| Deferred credits (f) | 42,711 | 21,168 |
| Preferred shares, Series C (g) | 13,418 | 14,718 |
| Other (h) | 39,710 | 45,434 |
| | 305,919 | 288,859 |
| Less: current portion | (42,337) | (46,754) |
| | $ 263,582 | $ 242,105 |

(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 5 to 40 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2018, $3,687 (2017 - $10,498) was transferred from advances in aid of construction to contributions in aid of construction.

## 12. Other long-term liabilities (continued)

(b) Environmental remediation obligation

A number of the Company's regulated utilities 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 historical 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 $59,181 (2017 - $57,292) which at discount rates ranging from 2.5% to 2.8% represents the recorded accrual of $55,621 as of December 31, 2018 (2017 - $54,322). Approximately $36,611 is expected to be incurred over the next four years with the balance of cash flows to be incurred over the following 27 years.

Changes in the environmental remediation obligation are as follows:

| | 2018 | 2017 |
|---|---|---|
| Opening balance | $ 54,322 | $ 47,202 |
| Remediation activities | (2,163) | (1,561) |
| Accretion | 1,479 | 1,114 |
| Changes in cash flow estimates | 4,051 | 1,645 |
| Revision in assumptions | (2,068) | 5,922 |
| Closing balance | $ 55,621 | $ 54,322 |

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, 2018, the Company has reflected a regulatory asset of $82,295 (2017 - $82,711) 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 Polychlorinated Biphenyls "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; (iv) remove certain river water intake structures and equipment; (v) disposal of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities.

Changes in the asset retirement obligations are as follows:

| | 2018 | 2017 |
|---|---|---|
| Opening Balance | $ 44,166 | $ 18,486 |
| Obligation assumed from business acquisition and constructed projects | 225 | 28,267 |
| Retirement activities | (5,130) | (2,811) |
| Accretion | 1,974 | 1,981 |
| Change in cash flow estimates | 2,056 | (1,757) |
| Closing Balance | $ 43,291 | $ 44,166 |

As the cost of retirement of utility assets, liability accretion and asset depreciation expense are expected to be recovered through rates, a corresponding regulatory asset is recorded (note 7(h)).

(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.

## 12. Other long-term liabilities (continued)

(e) Unamortized investment tax credits

The unamortized investment tax credits were assumed in connection with the acquisition of Empire. The investment tax credits are associated with an investment made in a generating station. The credits are being amortized over the life of the generating station.

(f) Deferred credits

During the year, the Company settled $16,000 of contingent consideration related to prior acquisitions resulting in a gain of approximately $12,000 which was recorded as a reduction of acquisition costs on the consolidated statements of operations.

(g) Preferred Shares, Series C

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 C$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 C$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 as follows:

| | | |
|---|---|---|
| 2019 | $ | 940 |
| 2020 | | 985 |
| 2021 | | 1,000 |
| 2022 | | 1,019 |
| 2023 | | 1,183 |
| Thereafter to 2031 | | 10,370 |
| Redemption amount | | 3,914 |
| | | 19,411 |
| Less: amounts representing interest | | (5,993) |
| | | 13,418 |
| Less current portion | | (940) |
| | $ | 12,478 |

(h) Other

Convertible debentures

As at December 31, 2018, the carrying value of the convertible debentures was $470 (2017 - $971).

On March 1, 2016, the Company completed the sale of C$1,150,000 aggregate principal amount of 5.0% convertible debentures. The proceeds received from the initial instalment in 2016 and the final instalment in 2017, net of financing costs were $266,889 and $571,642, respectively.

The convertible debentures mature on March 31, 2026 and bore interest at an annual rate of 5% per C$1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate is 0%. The interest expense recorded for the year ended December 31, 2018 is $nil (2017 - $7,193).

## 12. Other long-term liabilities (continued)

(h) Other (continued)

Convertible debentures (continued)

The debentures are convertible into up to 108,490,566 common shares. During the year ended December 31, 2018 $447 (2017 - $855,691) of principal converted to 56,926 (2017 - 108,370,081) common shares of the Company (note 13), representing conversion into common shares of 99.9% of the convertible debentures as at December 31, 2018.

## 13. Shareholders' capital

(a) Common shares

Number of common shares

| | 2018 | 2017 |
|---|---|---|
| Common shares, beginning of year | 431,765,935 | 274,087,018 |
| Public offering (a)(i) | 50,041,624 | 43,470,000 |
| Conversion of convertible debentures (note 12(h)) | 56,926 | 108,370,081 |
| Dividend reinvestment plan (a)(ii) | 5,880,843 | 3,905,848 |
| Exercise of share-based awards (c) | 1,106,105 | 1,932,988 |
| Common shares, end of year | 488,851,433 | 431,765,935 |

**Authorized**

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

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

(i) Public offering

On December 20, 2018, APUC issued 12,536,350 common shares at $10.09 (C$13.76) per share pursuant to a public offering for proceeds of $126,485 (C$172,500) before issuance costs of $366 (C$492).

On April 24, 2018, APUC issued 37,505,274 common shares at $9.23 (C$11.85) per share pursuant to a public offering for gross proceeds of $346,458 (C$444,437) before issuance costs of $590 (C$765).

On November 10, 2017, APUC issued 43,470,000 common shares at $10.45 (C$13.25) per share pursuant to a public offering for proceeds of $454,158 (C$576,000) before issuance costs of $19,193 (C$24,342) or $14,109 (C$17,895) net of taxes.

(ii) 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 1,606,001 common shares under the dividend reinvestment plan.

## 13. 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, 2018 and 2017:

| Preferred shares | Number of shares | Price per share | Carrying amount C$ | Carrying amount $ |
|---|---|---|---|---|
| Series A | 4,800,000 | C$ 25 | C$ 116,546 | $ 100,463 |
| Series D | 4,000,000 | C$ 25 | C$ 97,259 | $ 83,836 |
| | | | | $ 184,299 |

The holders of Series A preferred shares are entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The dividend for each year up to, but excluding December 31, 2018 was an annual amount of C$1.125 per share. The dividend rate for the five-year period from and including December 31, 2018 to but excluding December 31, 2023 will be $1.2905. The Series A dividend rate will reset on December 31, 2023 and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at C$25 per share at the option of the Company on December 31, 2023 and every fifth year thereafter.

The holders of Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of C$1.25 per share for each year up to, but excluding March 31, 2019. The Series D dividend rate will reset on that date and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D preferred shares are redeemable at C$25 per share at the option of the Company on March 31, 2019 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 A did not convert to Series B on December 31, 2018. 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, 2023 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 as they are mandatorily redeemable for cash (note 12(g)).

(c) Share-based compensation

For the year ended December 31, 2018, APUC recorded $9,458 (2017 - $8,361) in total share-based compensation expense detailed as follows:

| | 2018 | 2017 |
|---|---|---|
| Share options | $ 2,054 | $ 3,070 |
| Director deferred share units | 714 | 593 |
| Employee share purchase | 312 | 436 |
| Performance and restricted share units | 6,378 | 4,262 |
| Total share-based compensation | $ 9,458 | $ 8,361 |

## 13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

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, 2018, total unrecognized compensation costs related to non-vested options and PSUs were $1,221 and $8,243, respectively, and are expected to be recognized over a period of 1.64 and 1.60 years, respectively.

(i) Share option plan

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

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

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

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

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was based on experience to-date. 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:

| | 2018 | 2017 |
|---|---|---|
| Risk-free interest rate | 2.1% | 1.4% |
| Expected volatility | 21% | 25% |
| Expected dividend yield | 4.8% | 4.3% |
| Expected life | 5.50 years | 5.50 years |
| Weighted average grant date fair value per option | C$ 1.41 | C$ 1.45 |

## 13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

Share option activity during the years is as follows:

| | Number of awards | Weighted average exercise price | Weighted average remaining contractual term (years) | Aggregate intrinsic value |
|---|---|---|---|---|
| Balance, January 1, 2017 | 6,045,014 | C$ 9.64 | 6.27 | C$ 10,595 |
| Granted | 2,328,343 | 12.82 | 8.00 | — |
| Exercised | (1,634,501) | 7.81 | 3.76 | 7,696 |
| Balance, December 31, 2017 | 6,738,856 | C$ 11.18 | 6.32 | C$ 19,380 |
| Granted | 1,166,717 | 12.80 | 8.00 | — |
| Exercised | (1,589,211) | 10.66 | 5.02 | 5,059 |
| Forfeited | (23,720) | 12.80 | — | — |
| Balance, December 31, 2018 | 6,292,642 | C$ 11.61 | 5.75 | C$ 13,342 |
| Exercisable, December 31, 2018 | 3,198,175 | C$ 10.44 | 4.93 | C$ 10,501 |

(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 dollars 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, 2018, a total of 252,698 common shares (2017 - 283,523) were issued to employees under the ESPP.

(iii) Director's 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, 2018, 380,656 (2017 - 293,906) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU plan shall not exceed 1,000,000 common shares.

## 13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance and restricted share units

The Company offers a PSU and RSU 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 2.0% to 237% of the number of PSUs granted. RSU vesting conditions and dates vary by grant and are outlined in each award letter. RSUs are not subject to performance criteria. Dividends accumulating during the vesting period are converted to PSUs and RSUs 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 or RSUs have voting rights. Any PSUs or RSUs 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. The aggregate number of common shares reserved for issuance from treasury by APUC under the PSU and RSU Plan shall not exceed 7,000,000 common shares.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the consolidated balance sheet dates. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date.

A summary of the PSUs and RSUs follows:

| | Number of awards | Weighted average grant-date fair value | Weighted average remaining contractual term (years) | Aggregate intrinsic value |
|---|---|---|---|---|
| Balance, January 1, 2017 | 578,988 | C$ 9.82 | 1.74 | C$ 6,595 |
| Granted, including dividends | 811,974 | 13.54 | 2.00 | — |
| Exercised | (374,973) | 8.33 | — | 4,394 |
| Forfeited | (60,961) | 12.61 | — | — |
| Balance, December 31, 2017 | 955,028 | C$ 12.30 | 1.84 | C$ 13,428 |
| Granted, including dividends | 791,524 | 12.41 | 2.00 | — |
| Exercised | (285,551) | 10.02 | — | 3,691 |
| Forfeited | (68,869) | 13.02 | — | — |
| Balance, December 31, 2018 | 1,392,132 | C$ 12.75 | 1.60 | C$ 19,114 |
| Exercisable, December 31, 2018 | 173,533 | C$ 11.66 | — | C$ 2,383 |

(v) Bonus deferral RSUs

During the year, the Company introduced a new bonus deferral RSU program to certain of its employees. Eligible employees have the option to receive a portion or all of their annual bonus payment in RSUs in lieu of cash. The RSUs provide for settlement in shares, and therefore these options are accounted for as equity awards. The RSUs granted are 100% vested and therefore, compensation expense associated with RSUs is recognized immediately upon issuance.

## 13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Bonus deferral RSUs

A summary of the bonus deferral RSUs follows:

| | Number of awards | Weighted average grant-date fair value | Aggregate intrinsic value |
|---|---|---|---|
| Balance, December 31, 2017 | — | C$ — | $ — |
| Granted, including dividends | 131,611 | 12.82 | — |
| Exercised | (4,545) | 12.82 | 61 |
| Balance and exercisable, December 31, 2018 | 127,066 | C$ 12.82 | C$ 1,745 |

## 14. 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, 2017 | $ (25,921) | $ 53,740 | $ 65 | $ (10,833) | $ 17,051 |
| OCI (loss) before reclassifications | (21,780) | 8,004 | — | 600 | (13,176) |
| Amounts reclassified | — | (6,378) | (65) | (224) | (6,667) |
| Net current period OCI | (21,780) | 1,626 | (65) | 376 | (19,843) |
| Balance, December 31, 2017 | $ (47,701) | $ 55,366 | $ — | $ (10,457) | $ (2,792) |
| Cumulative catch-up adjustment related to adoption of ASU 2018-02 on tax effects in AOCI (note 2(a)) | — | 11,657 | — | (1,032) | 10,625 |
| OCI before reclassifications | (26,488) | 1,567 | — | 2,046 | (22,875) |
| Amounts reclassified | — | (4,257) | — | (86) | (4,343) |
| Net current period OCI | $ (26,488) | $ (2,690) | $ — | $ 1,960 | $ (27,218) |
| Balance, December 31, 2018 | $ (74,189) | $ 64,333 | $ — | $ (9,529) | $ (19,385) |

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 pension and post-employment non-service costs.

## 15. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividends on its common shares in U.S. dollars. Dividends declared during the year were as follows:

| | 2018 | | 2017 | |
|---|---|---|---|---|
| | Dividend | Dividend per share | Dividend | Dividend per share |
| Common shares | $ 235,440 | $ 0.5011 | $ 185,915 | $ 0.4660 |
| Series A preferred shares | C$ 5,400 | C$ 1.1250 | C$ 5,400 | C$ 1.1250 |
| Series D preferred shares | C$ 5,000 | C$ 1.2500 | C$ 5,000 | C$ 1.2500 |

## 16. Related party transactions

*Equity-method investments*

The Company entered in a number of transactions with equity-method investees in 2018 and 2017 (note 8). In addition, the Company provides administrative and development services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $11,390 (2017 - $4,675) during the year.

Subject to certain limitations, Atlantica has a right of first offer on any proposed sale, transfer or other disposition by the AAGES entities (other than to APUC) of its interest in infrastructure facilities that are developed or constructed in whole or in part by the AAGES entities under long-term revenue agreements. Similarly, Atlantica has rights, subject to certain limitations, with respect to any proposed sale, transfer or other disposition of APUC's interest, not held through the AAGES entities, in infrastructure facilities that are developed or constructed in whole or in part by APUC outside of Canada or the United States under long-term revenue agreements. There were no such transactions in 2018.

*Redeemable non-controlling interests*

In 2018, contributions of $305,000 were received from AAGES B.V for a preference share of AY Holdings (note 8(a) and note 17).

*Long Sault Hydro Facility*

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

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

## 17. Non-controlling interests and redeemable non-controlling interests

Net effect attributable to non-controlling interests for the years ended December 31 consists of the following:

| | 2018 | 2017 |
|---|---|---|
| HLBV and other adjustments attributable to: | | |
| Non-controlling interests - Class A partnership units | $ 103,150 | $ 39,850 |
| Non-controlling interests - redeemable Class A partnership units | 7,545 | 10,358 |
| Other net earnings attributable to: | | |
| Non-controlling interests | (2,174) | (2,438) |
| | $ 108,521 | $ 47,770 |
| Redeemable non-controlling interests, held by related party | (2,622) | — |
| Net effect of non-controlling interests | $ 105,899 | $ 47,770 |

## 17. Non-controlling interests and redeemable non-controlling interests (continued)

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

The terms of the arrangement refer to the tax rate in effect when the benefits are delivered. As such, The U.S. federal corporate tax rate of 35% was used to calculate HLBV as at December 31, 2017. The reduced U.S. federal corporate tax rate of 21% and other certain measures included in the Tax Act effective January 1, 2018 were reflected in the calculation of HLBV in 2018. The changes accelerated HLBV income from future years to the first quarter of 2018 in the amount of $55,900.

*Non-controlling interests*

As of December 31, 2018, non-controlling interests of $519,896 (2017 - $602,636) includes Class A partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $519,100 (2017 - $601,780) and other non-controlling interests of $796 (2017 - $856). Contributions from Class A partnership investors of $15,250 and $42,750 was received for the Great Bay Solar Facility in 2018 and 2017, respectively (note 3(d)); $9,800 was received for the Bakersfield II Solar Facility on February 28, 2017 (note 3(g)); and, $166,595 was received for the Deerfield Wind Project on May 10, 2017 (note 8(f)(ii)).

*Redeemable non-controlling interests*

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. If the redemption is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2018. Changes in redeemable non-controlling interests are as follows:

| | Redeemable non-controlling interests held by related party | | Redeemable non-controlling interests | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Opening balance | $ — | $ — | $ 41,553 | $ 21,922 |
| Net effect from operations | 2,622 | — | (7,545) | (10,356) |
| Contributions, net of costs | 305,000 | — | — | 31,105 |
| Dividends and distributions declared | — | — | (644) | (1,118) |
| Closing balance | $ 307,622 | $ — | $ 33,364 | $ 41,553 |

Contributions of $305,000 were received from Abengoa-Algonquin Global Energy Solutions B.V. for a preference share of AY Holdings (note 8(a)). Contributions from Class A partnership investors of $31,212 were received for the Luning Solar Facility on February 17, 2017 (note 3(f)).

## 18. 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% (2017 - 26.5%). The differences are as follows:

| | 2018 | 2017 |
|---|---|---|
| Expected income tax expense at Canadian statutory rate | $ 35,102 | $ 46,410 |
| Increase (decrease) resulting from: | | |
| Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates | (34,165) | (20,987) |
| Net loss from investment in Atlantica | 25,870 | — |
| Base Erosion Anti-Abuse Tax | 6,101 | — |
| Non-controlling interests share of income | 29,637 | 18,979 |
| Allowance for equity funds used during construction | (719) | (799) |
| Capital gain rate differential | 722 | (687) |
| Goodwill divestiture and permanent basis differences associated with Mountain Water condemnation | 58 | 5,489 |
| Non-deductible acquisition costs | 4,267 | 13,660 |
| Change in valuation allowance | 1,160 | (974) |
| Tax credits | (1,419) | (6,288) |
| Adjustment relating to prior periods | 3,673 | (31) |
| U.S. Tax reform and related deferred tax adjustments | (18,363) | 17,112 |
| Other | 1,448 | 1,543 |
| Income tax expense | $ 53,372 | $ 73,427 |

On December 22, 2017, the Tax Act was signed into legislation. The Tax Act includes a broad range of legislative changes including a reduction of the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018, limitations on the deductibility of interest and 100% expensing of qualified property. The Tax Act provides an exemption to regulated utilities from the limitations on the deductibility of interest and also does not permit regulated utilities to immediately expense 100% of the cost of new investments in qualified property.

As a result of the Tax Act being enacted during 2017, the Company was required to revalue its United States deferred income tax assets and liabilities based on the rates they are expected to reverse at in the future, which is generally 21% for U.S. federal tax purposes. The Company recognized a provisional charge to income tax expense of $17,112 in 2017 as a result of the revaluation of its U.S. non-regulated net deferred income tax assets. In 2018, the Company completed its remeasurement of deferred income tax assets and liabilities as permitted under the measurement period outlined under SEC Staff Accounting Bulletin 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (“SAB 118”). The final adjustments related to the implementation of U.S. Tax Reform resulted in a non-cash accounting benefit of $18,363 which was recorded in the Company's 2018 consolidated statement of operations.

On June 1, 2018, the State of Missouri enacted legislation that, effective for tax years beginning on or after January 1, 2020, reduces the corporate income tax rate from 6.25% to 4%, among other legislative changes. The Company reduced its regulated net deferred income tax liabilities by $15,586 and recorded an equivalent increase to net regulatory liabilities since the benefit of lower Missouri state income taxes is probable of being returned to customers by order of the applicable regulator.

For the years ended December 31, 2018 and 2017, earnings before income taxes consist of the following:

| | 2018 | 2017 |
|---|---|---|
| Canada | $ (109,537) | $ (2,711) |
| U.S. | 241,998 | 177,843 |
| | $ 132,461 | $ 175,132 |

## 18. Income taxes (continued)

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

| | Current | Deferred | Total |
|---|---|---|---|
| Year ended December 31, 2018 | | | |
| Canada | $ 2,872 | $ (14,197) | $ (11,325) |
| United States | 8,475 | 56,222 | 64,697 |
| | $ 11,347 | $ 42,025 | $ 53,372 |
| Year ended December 31, 2017 | | | |
| Canada | $ 3,296 | $ (14,168) | $ (10,872) |
| United States | 4,221 | 80,078 | 84,299 |
| | $ 7,517 | $ 65,910 | $ 73,427 |

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, 2018 and 2017 are presented below:

| | 2018 | 2017 |
|---|---|---|
| Deferred tax assets: | | |
| Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs | $ 329,099 | $ 328,679 |
| Pension and OPEB | 48,586 | 43,638 |
| Acquisition-related costs | 1,420 | 1,601 |
| Environmental obligation | 14,790 | 14,803 |
| Reserves and other non-deductible costs | 20,517 | 30,652 |
| Regulatory liabilities | 161,560 | 154,597 |
| Financial derivatives | 12,831 | 7,607 |
| Other | 10,425 | 16,384 |
| Total deferred income tax assets | 599,228 | 597,961 |
| Less valuation allowance | (28,018) | (19,951) |
| Total deferred tax assets | 571,210 | 578,010 |
| Deferred tax liabilities: | | |
| Property, plant and equipment | (653,962) | (668,083) |
| Intangible assets | (7,247) | (7,157) |
| Outside basis in partnership | (167,659) | (125,519) |
| Regulatory accounts | (113,758) | (114,062) |
| Financial derivatives | — | (980) |
| Other | (314) | — |
| Total deferred tax liabilities | (942,940) | (915,801) |
| Net deferred tax liabilities | $ (371,730) | $ (337,791) |
| **Consolidated Balance Sheets Classification:** | | |
| Deferred tax assets | $ 72,415 | $ 61,357 |
| Deferred tax liabilities | (444,145) | (399,148) |
| Net deferred tax liabilities | $ (371,730) | $ (337,791) |

## 18. Income taxes (continued)

The valuation allowance for deferred tax assets as at December 31, 2018 was $28,018 (2017 - $19,951). 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, 2018, the Company had non-capital losses carried forward available to reduce future year's taxable income, which expire as follows:

| Year of expiry | Non-capital loss carryforwards |
|---|---|
| 2020 and onwards | $ 925,439 |

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 $280,643 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.

## 19. 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 bonus deferral restricted share units outstanding. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs, RSUs 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 convertible debentures (note 12(h)) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The Final Instalment Date occurred on February 2, 2017, and as such, the shares issuable upon conversion of the convertible debentures are included in diluted earnings per share beginning on that date.

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:

| | 2018 | 2017 |
|---|---|---|
| Net earnings attributable to shareholders of APUC | $ 184,988 | $ 149,475 |
| Series A Preferred shares dividend | 4,169 | 4,164 |
| Series D Preferred shares dividend | 3,858 | 3,856 |
| Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted | $ 176,961 | $ 141,455 |
| Weighted average number of shares | | |
| Basic | 461,818,023 | 382,323,434 |
| Effect of dilutive securities | 4,227,595 | 3,662,714 |
| Diluted | 466,045,618 | 385,986,148 |

The shares potentially issuable as a result of 3,380,184 share options (2017 - 2,328,343) are excluded from this calculation as they are anti-dilutive.

## 20. Segmented information

The Company is managed under two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The two business units are the two segments of the Company.

The Liberty Power Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets in North America and internationally; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations in the United States.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. Dividend income from Atlantica (note 8(a)) and equity income from the AAGES entities (note 8(b)) are included in the operations of the Liberty Power Group. The change in value of the investment in Atlantica carried at fair value (note 8(a)) and unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship are not considered in management's evaluation of divisional performance and are therefore allocated and reported under corporate. The results of operations and assets for these segments are reflected in the tables below.

| | Year ended December 31, 2018 | | | |
|---|---|---|---|---|
| | Liberty Utilities Group | Liberty Power Group | Corporate | Total |
| Revenue (1)(2) | $ 1,400,164 | $ 247,223 | $ — | $ 1,647,387 |
| Fuel, power and water purchased | 456,974 | 27,164 | — | 484,138 |
| Net revenue | 943,190 | 220,059 | — | 1,163,249 |
| Operating expenses | 401,486 | 70,980 | — | 472,466 |
| Administrative expenses | 33,234 | 18,539 | 937 | 52,710 |
| Depreciation and amortization | 177,719 | 82,044 | 1,009 | 260,772 |
| Gain on foreign exchange | — | — | (58) | (58) |
| Operating income | 330,751 | 48,496 | (1,888) | 377,359 |
| Interest expense | 99,063 | 50,920 | 2,135 | 152,118 |
| Interest, dividend, equity and other income | (5,558) | (45,741) | (1,840) | (53,139) |
| Change in value of investment carried at fair value | — | — | 137,957 | 137,957 |
| Other expenses | 5,699 | 1,576 | 687 | 7,962 |
| Earnings (loss) before income taxes | $ 231,547 | $ 41,741 | $ (140,827) | $ 132,461 |
| Property, plant and equipment | $ 4,210,115 | $ 2,152,420 | $ 31,023 | $ 6,393,558 |
| Investment carried at fair value | — | 814,530 | — | 814,530 |
| Equity-method investees | 959 | 29,273 | 260 | 30,492 |
| Total assets | 6,012,641 | 3,269,786 | 106,541 | 9,388,968 |
| Capital expenditures | 370,221 | 96,148 | — | 466,369 |

(1) Revenue includes $14,953 related to net hedging gains from energy derivative contracts for the twelve months ended December 31, 2018 that do not represent revenue recognized from contracts with customers.

(2) Liberty Utilities Group revenue includes $7,425 related to alternative revenue programs for the twelve months ended December 31, 2018 that do not represent revenue recognized from contracts with customers.

20. **Segmented information (continued)**

| | Year ended December 31, 2017 | | | |
|---|---|---|---|---|
| | Liberty Utilities Group | Liberty Power Group | Corporate | Total |
| Revenue | $ 1,290,786 | $ 231,152 | $ — | $ 1,521,938 |
| Fuel and power purchased | 373,635 | 19,590 | — | 393,225 |
| Net revenue | 917,151 | 211,562 | — | 1,128,713 |
| Operating expenses | 383,380 | 66,851 | — | 450,231 |
| Administrative expenses | 33,037 | 15,992 | 611 | 49,640 |
| Depreciation and amortization | 171,111 | 79,183 | 1,020 | 251,314 |
| Gain on foreign exchange | — | — | 323 | 323 |
| Operating income (loss) | 329,623 | 49,536 | (1,954) | 377,205 |
| Interest expense | 97,698 | 36,646 | 21,478 | 155,822 |
| Interest, dividend and other income | (4,208) | (2,871) | (2,159) | (9,238) |
| Other expense | 6,087 | 1,713 | 47,689 | 55,489 |
| Earnings (loss) before income taxes | $ 230,046 | $ 14,048 | $ (68,962) | $ 175,132 |
| Property, plant and equipment | $ 4,023,479 | $ 2,246,869 | $ 34,549 | $ 6,304,897 |
| Equity-method investees | 2,220 | 29,710 | 337 | 32,267 |
| Total assets | 5,817,599 | 2,474,293 | 103,675 | 8,395,567 |
| Capital expenditures | 407,408 | 157,695 | — | 565,103 |

The majority of non-regulated energy sales are earned from contracts with large public utilities. The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations. None of the utilities contribute more than 10% of total revenue.

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:

| | 2018 | 2017 |
|---|---|---|
| Revenue | | |
| Canada | $ 70,358 | $ 73,406 |
| United States | 1,577,029 | 1,448,532 |
| | $ 1,647,387 | $ 1,521,938 |
| Property, plant and equipment | | |
| Canada | $ 415,979 | $ 453,323 |
| United States | 5,977,579 | 5,851,574 |
| | $ 6,393,558 | $ 6,304,897 |
| Intangible assets | | |
| Canada | $ 23,994 | $ 27,624 |
| United States | 31,000 | 23,479 |
| | $ 54,994 | $ 51,103 |

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

## 21. Commitments and contingencies

(a) Contingencies

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

*Claim by Gaia Power Inc.*

On October 30, 2018, Gaia Power Inc. ("Gaia") commenced an action in the Ontario Superior Court of Justice against APUC and certain of its subsidiaries, claiming damages of not less than $345,000 and punitive damages in the sum of $25,000. The action arises from Gaia's 2010 sale, to a subsidiary of APUC, of Gaia's interest in certain proposed wind farm projects in Canada. Pursuant to a 2010 royalty agreement, Gaia is entitled to royalty payments if the projects are developed and achieve certain agreed targets. APUC believes that the claims are without merit, and intends to vigorously defend the action.

*Condemnation Expropriation Proceedings*

Liberty Utilities (Apple Valley Ranchos Water) Corp. is the subject of a condemnation lawsuit filed by the town of Apple Valley. A Court will determine the necessity of the taking by Apple Valley and, if established, a jury will determine the fair market value of the assets being condemned. Resolution of the condemnation proceedings is expected to take two to three years. Any taking by government entities would legally require fair compensation to be paid, however, there is no assurance that the value received as a result of the condemnation will be sufficient to recover the Company's net book value of the utility assets taken.

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula could proceed with condemnation of Mountain Water's assets. The fair market value of the condemned property as of May 6, 2014 was assessed by the Commissioners to be $88,600. Upon taking possession of Mountain Water's assets on June 22, 2017, the city of Missoula paid $83,863 to Mountain Water, net of closing adjustments and amounts required to be paid by the City directly to various developers in satisfaction of obligations under Funded By Other contracts relating to the assets.

The condemnation of the Mountain Water assets resulted in a gain on long-lived assets of $4,370.

## 21. Commitments and contingencies (continued)

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2018.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases.

Detailed below are estimates of future commitments under these arrangements:

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Power purchase (i) | $ 46,536 | $ 10,896 | $ 11,114 | $ 11,338 | $ 11,566 | $ 191,208 | $ 282,658 |
| Gas supply and service agreements (ii) | 77,658 | 51,349 | 27,672 | 24,422 | 22,424 | 48,313 | 251,838 |
| Service agreements | 43,732 | 39,093 | 38,451 | 37,463 | 40,737 | 312,559 | 512,035 |
| Capital projects | 67,575 | 1,663 | 196 | 7,330 | — | — | 76,764 |
| Operating leases | 7,629 | 7,154 | 7,096 | 7,076 | 6,776 | 178,583 | 214,314 |
| Total | $ 243,130 | $ 110,155 | $ 84,529 | $ 87,629 | $ 81,503 | $ 730,663 | $ 1,337,609 |

(i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above are based on market prices as of December 31, 2018. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

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

## 22. Non-cash operating items

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

| | 2018 | 2017 |
|---|---|---|
| Accounts receivable | $ 3,005 | $ (45,818) |
| Fuel and natural gas in storage | 1,351 | (4,385) |
| Supplies and consumables inventory | (7,189) | (1,864) |
| Income taxes recoverable | (763) | (557) |
| Prepaid expenses | 2,907 | (2,755) |
| Accounts payable | (22,915) | 7,525 |
| Accrued liabilities | 28,687 | 14,041 |
| Current income tax liability | 2,974 | (3,190) |
| Asset retirements and environmental obligations | (7,293) | (4,372) |
| Net regulatory assets and liabilities | (8,890) | (46,344) |
| | $ (8,126) | $ (87,719) |

## 23. Financial instruments

(a) Fair value of financial instruments

| 2018 | Carrying amount | Fair value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| Notes receivable | $ 103,696 | $ 110,019 | $ — | $ 110,019 | $ — |
| Investment in Atlantica | 814,530 | 814,530 | 814,530 | — | — |
| Derivative instruments (1): | | | | | |
| Energy contracts designated as a cash flow hedge | 61,838 | 61,838 | — | — | 61,838 |
| Currency forward contract not designated as a hedge | 869 | 869 | — | 869 | — |
| Commodity contracts for regulated operations | 101 | 101 | — | 101 | — |
| Total derivative instruments | 62,808 | 62,808 | — | 970 | 61,838 |
| Total financial assets | $ 981,034 | $ 987,357 | $ 814,530 | $ 110,989 | $ 61,838 |
| Long-term debt | $ 3,336,795 | $ 3,356,773 | $ 768,400 | $ 2,588,373 | $ — |
| Convertible debentures | 470 | 639 | 639 | — | — |
| Preferred shares, Series C | 13,418 | 13,703 | — | 13,703 | — |
| Derivative instruments: | | | | | |
| Energy contracts designated as a cash flow hedge | 57 | 57 | — | — | 57 |
| Cross-currency swap designated as a net investment hedge | 93,198 | 93,198 | — | 93,198 | — |
| Interest rate swap designated as a hedge | 8,473 | 8,473 | — | 8,473 | — |
| Commodity contracts for regulated operations | 1,114 | 1,114 | — | 1,114 | — |
| Total derivative instruments | 102,842 | 102,842 | — | 102,785 | 57 |
| Total financial liabilities | $ 3,453,525 | $ 3,473,957 | $ 769,039 | $ 2,704,861 | $ 57 |

## 23. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

| 2017 | Carrying amount | Fair value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| Notes receivable | $ 33,378 | $ 38,192 | $ — | $ 38,192 | $ — |
| Derivative instruments (1): | | | | | |
| Energy contracts designated as a cash flow hedge | 63,363 | 63,363 | — | — | 63,363 |
| Energy contracts not designated as a cash flow hedge | 109 | 109 | — | 109 | — |
| Commodity contracts for regulatory operations | 74 | 74 | — | 74 | — |
| Total derivative instruments | 63,546 | 63,546 | — | 183 | 63,363 |
| Total financial assets | $ 96,924 | $ 101,738 | $ — | $ 38,375 | $ 63,363 |
| Long-term debt | $ 3,079,551 | $ 3,262,711 | $ 651,969 | $ 2,610,742 | $ — |
| Convertible debentures | 971 | 1,018 | 1,018 | — | — |
| Preferred shares, Series C | 14,718 | 15,124 | — | 15,124 | — |
| Derivative instruments: | | | | | |
| Energy contracts designated as a cash flow hedge | 77 | 77 | — | — | 77 |
| Energy contracts not designated as a cash flow hedge | 31 | 31 | — | 31 | — |
| Cross-currency swap designated as a net investment hedge | 57,412 | 57,412 | — | 57,412 | — |
| Interest rate swaps designated as a hedge | 8,460 | 8,460 | — | 8,460 | — |
| Currency forward contract not designated as hedge | 344 | 344 | — | 344 | — |
| Commodity contracts for regulated operations | 2,620 | 2,620 | — | 2,620 | — |
| Total derivative instruments | 68,944 | 68,944 | — | 68,867 | 77 |
| Total financial liabilities | $ 3,164,184 | $ 3,347,797 | $ 652,987 | $ 2,694,733 | $ 77 |

(1) Balance of $441 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2018 and 2017 due to the short-term maturity of these instruments.

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

The fair value of the investment in Atlantica (level 1) is measured at the closing price on the NASDAQ stock exchange.

## 23. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company's level 1 fair value of long-term debt is measured at the closing price on the NYSE stock exchange and the Canadian over-the-counter closing price. The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates. The Company's level 2 fair value of convertible debentures has been determined as the greater of their face value and the quoted value of APUC's common shares on a converted basis.

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

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $14.55 to $172.97 with a weighted average of $24.72 as of December 31, 2018. The weighted average forward market prices are developed based on the quantity of energy expected to be sold monthly and the expected forward price during that month. Significant increases (decreases) in any of these inputs in isolation would have resulted in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 23(b)(ii) and 23(b)(iv).

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

(b) Derivative instruments

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

(i) Commodity derivatives – regulated accounting

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

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

| | 2018 |
|---|---|
| Financial contracts: Swaps | 2,366,386 |
| Options | 300,000 |
| Forward contracts | 6,560,000 |

The accounting for these derivative instruments is subject to guidance for rate regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Most of the gains or losses on the settlement of these contracts are included in the calculation of the fuel and commodity costs adjustments (note 7(d)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

## 23. Financial instruments (continued)

(b) Derivative instruments

(i) Commodity derivatives – regulated accounting (continued)

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

| | 2018 | 2017 |
|---|---|---|
| Regulatory assets: | | |
| Swap contracts | $ 66 | $ — |
| Forward contracts | $ — | $ 6,319 |
| Regulatory liabilities: | | |
| Swap contracts | $ 218 | $ 287 |
| Option contracts | $ 134 | $ 138 |
| Forward contracts | $ 1,259 | $ — |

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

| Notional quantity (MW-hrs) | Expiry | Receive average prices (per MW-hr) | Pay floating price (per MW-hr) |
|---|---|---|---|
| 871,391 | December 2028 | 36.33 | PJM Western HUB |
| 2,438,697 | December 2023 | 29.06 | PJM NI HUB |
| 2,997,939 | December 2027 | 36.46 | ERCOT North HUB |

Subsequent to year-end, the Company entered into a long-term energy derivative contract for the Minonk Wind Facility with a notional quantity of 251,581 MW-hours and a price of $20.72 per MW-hr. The contract expires December 2024.

The Company was party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year C$135,000 bond. During the year, the Company amended and extended the forward-starting date of the interest rate swap to begin on March 29, 2019. As a result of the amendment, $898 of hedge ineffectiveness was recognized in earnings upon hedge dedesignation. The change in fair value since the hedge redesignation date is recorded in OCI. Subsequent to year end, the Company settled the forward-starting interest rate swap contract as it issued C$300,000 10-year senior unsecured notes with an interest rate of 4.60% (note 9(g)).

In 2017, the Company settled forward contracts to purchase $250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and $250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% designated as hedges to the interest rate risk related to $479,000 of senior unsecured notes. The effective portion of the hedge was recorded in OCI at the time and is reclassified to interest expense as the underlying hedged transactions are incurred.

## 23. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

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

| | 2018 | 2017 |
|---|---|---|
| Effective portion of cash flow hedge | $ 1,567 | $ 8,004 |
| Amortization of cash flow hedge | (33) | (27) |
| Amounts reclassified from AOCI | (4,224) | (6,351) |
| OCI attributable to shareholders of APUC | $ (2,690) | $ 1,626 |

The Company expects $6,289 and $989 of unrealized gains currently in AOCI to be reclassified, net of taxes into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

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

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

The Company's Canadian operations are determined to have the Canadian dollar as their functional currency and are exposed to currency fluctuations from their U.S. dollar transactions. The Company designates the amounts drawn on its revolving and bank credit facilities denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in its U.S. investments and subsidiaries. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency loss of $37,204 for the year ended December 31, 2018 (2017 - gain of $17,817) was recorded in OCI.

Concurrent with its C$150,000, C$200,000 and C$300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A loss of $41,244 (2017 - gain of $19,063) was recorded in OCI in 2018.

(iv) Other derivatives

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

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

## 23. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project-specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 23(b)(ii)).

The Company is exposed to foreign exchange fluctuations related to the portion of its dividend declared and payable in U.S. dollars. This risk is mitigated through the use of currency forward contracts. For the year ended December 31, 2018, a loss on foreign exchange gain of $1,115 (2017 - loss of $297) was recorded in the consolidated statements of operations. These currency forward contracts are not accounted for as a hedge.

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

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

| | 2018 | 2017 |
|---|---|---|
| Change in unrealized loss (gain) on derivative financial instruments: | | |
| Energy derivative contracts | $ 77 | $ (79) |
| Currency forward contract | (1,230) | 297 |
| Commodity contracts | — | (2,885) |
| Total change in unrealized gain on derivative financial instruments | $ (1,153) | $ (2,667) |
| Realized loss (gain) on derivative financial instruments: | | |
| Interest rate swaps | — | (144) |
| Energy derivative contracts | (73) | 553 |
| Currency forward contract | 115 | 12,261 |
| Total realized loss on derivative financial instruments | $ 42 | $ 12,670 |
| Loss (gain) on derivative financial instruments not accounted for as hedges | (1,111) | 10,003 |
| Ineffective portion of derivative financial instruments accounted for as hedges | 632 | 637 |
| | $ (479) | $ 10,640 |
| Amounts recognized in the consolidated statements of operations consist of: | | |
| Loss (gain) on derivative financial instruments | 636 | (1,918) |
| Loss (gain) on foreign exchange | (1,115) | 12,558 |
| | $ (479) | $ 10,640 |

## 23. Financial instruments (continued)

(c) Risk management

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

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

*Credit risk*

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders all of which have a credit rating of A or better. The Company does not consider the risk associated with the Liberty Power Group accounts receivable to be significant as over 84% of revenue from power generation is earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS. Revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of $207,740 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2018, the Company's maximum exposure to credit risk for these financial instruments was as follows:

| | December 31, 2018 | |
|---|---|---|
| | Canadian $ | US $ |
| Cash and cash equivalents and restricted cash | $ 27,720 | $ 45,452 |
| Accounts receivable | 13,562 | 241,068 |
| Allowance for doubtful accounts | — | (5,281) |
| Notes receivable | 138,353 | 2,279 |
| | $ 179,635 | $ 283,518 |

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

*Liquidity risk*

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2018, in addition to cash on hand of $46,819 the Company had $1,046,826 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

## 23. Financial instruments (continued)

(c) Risk management (continued)

*Liquidity risk (continued)*

The Company's liabilities mature as follows:

| | Due less than 1 year | Due 2 to 3 years | Due 4 to 5 years | Due after 5 years | Total |
|---|---|---|---|---|---|
| Long-term debt obligations | $ 334,855 | $ 420,797 | $ 825,596 | $ 1,740,471 | $ 3,321,719 |
| Convertible debentures | — | — | — | 470 | 470 |
| Advances in aid of construction | 1,205 | — | — | 62,498 | 63,703 |
| Interest on long-term debt | 156,768 | 269,942 | 221,528 | 928,736 | 1,576,974 |
| Purchase obligations | 325,326 | — | — | — | 325,326 |
| Environmental obligation | 4,158 | 30,140 | 2,885 | 21,998 | 59,181 |
| Derivative financial instruments: | | | | | |
| Cross-currency swap | 5,277 | 46,026 | 34,436 | 7,459 | 93,198 |
| Interest rate swaps | 8,473 | — | — | — | 8,473 |
| Currency forward | — | — | — | — | — |
| Energy derivative and commodity contracts | 588 | 526 | 57 | — | 1,171 |
| Other obligations | 33,350 | — | — | 122,408 | 155,758 |
| Total obligations | $ 870,000 | $ 767,431 | $ 1,084,502 | $ 2,884,040 | $ 5,605,973 |

## 24. Comparative figures

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

**Exhibit 99.3**

ALGONQUIN Power & Utilities Corp.

# Management Discussion & Analysis

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company" or the "Corporation") 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, 2018. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's annual audited consolidated financial statements for the years ended December 31, 2018 and 2017. This material is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar, 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 and on EDGAR at www.sec.gov/edgar.

Unless otherwise indicated, financial information provided for the years ended December 31, 2018 and 2017 has been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"). As a result, the Company's financial information may not be comparable with financial information of other Canadian companies that provide financial information on another basis.

All monetary amounts are in thousands of U.S. dollars, except where otherwise noted. We denote any amounts denominated in Canadian dollars with "C$" immediately prior to the stated amount.

This MD&A is based on information available to management as of February 28, 2019.

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## Caution Concerning Forward-looking Statements, Forward-looking Information and Non-GAAP Measures

### Forward-looking Statements and Forward-Looking Information

This document may contain statements that constitute "forward-looking information" within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate reviews, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; expectations regarding the use of proceeds from equity financing; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the Company's corporate development activities and the results thereof; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans, sources of funds and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; expectations regarding the impact of tax reforms; credit ratings; anticipated growth and emerging opportunities in APUC's target markets; accounting estimates; interest rates; currency exchange rates; and commodity prices. All forward-looking information is given pursuant to the "safe harbor" provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational disruptions or liability due to natural disasters or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation's acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation's facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify, acquire or develop appropriate projects to maximize the value of PTC qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects; loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's interests; a drop in the market value of Atlantica's ordinary shares; facilities being condemned or otherwise taken by governmental entities; increased external-stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Corporation's Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "*Enterprise Risk Management*" and in the Corporation's most recent AIF.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by law. All forward-looking information contained herein is qualified by these cautionary statements.

## Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under U.S. GAAP. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

Adjusted EBITDA

Adjusted 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, non-service pension and post-employment costs, cost related to tax equity financing, gain or loss on foreign exchange, earnings or loss from discontinued operations, changes in value of investments carried at fair value, 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 U.S. GAAP, and can be impacted positively or negatively by these items.

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, one-time costs of arranging tax equity financing, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations, unrealized mark-to-market revaluation impacts, changes in value of investments carried at fair value, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. The Non-cash accounting charge related to the revaluation of U.S. deferred income tax assets and liabilities as a result of implementation of the effects of U.S. Tax Reform is adjusted as it is also considered a non-recurring item 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. Adjusted Net Earnings is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, and can be impacted positively or negatively by these items.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable): changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. 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. Adjusted Funds from Operations is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, and can be impacted positively or negatively by these items.

Net Energy Sales

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

Net Utility Sales

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

Divisional Operating Profit

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

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

## Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is $0.1282 per common share or $0.5128 per common share per annum. Based on exchange rates as at February 27, 2019, the quarterly dividend is equivalent to C$0.1685 per common share or C$0.6740 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Changes 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 APUC's financial performance and growth prospects.

APUC's operations are organized across two primary North American business units consisting of: the Liberty Utilities Group, which primarily owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations; and the Liberty Power Group, which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets. APUC also owns a 41.5% beneficial stake in Atlantica Yield plc (NASDAQ: AY) ("Atlantica"), a company that acquires, owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission, and water assets. The investment in Atlantica is reported under the Liberty Power Group.

### Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 768,000 connections. The Liberty Utilities Group seeks to provide safe, high quality, and reliable services to its customers and to deliver stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group seeks to deliver continued growth in earnings through accretive acquisitions of additional utility systems.

The Liberty Utilities Group's regulated electrical distribution utility systems and related generation assets are located in the States of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas which together serve approximately 266,000 electric connections. The group also owns and manages generating assets with a gross capacity of approximately 1.7 GW and has investments in a further approximately 0.3 GW of net generation capacity.

The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri which together serve approximately 338,000 natural gas connections.

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, and Texas which together serve approximately 164,000 connections.

### Liberty Power Group

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

The Liberty Power Group owns and operates hydroelectric, wind, solar, and thermal facilities with a combined gross generating capacity of approximately 1.5 GW. Approximately 86% of the electrical output is sold pursuant to long term contractual arrangements which as of December 31, 2018 had a production-weighted average remaining contract life of approximately 14 years.

APUC has a 41.5% interest in Atlantica. Atlantica owns and operates a portfolio of international clean energy and water infrastructure assets under long term contracts with a Cash Available for Distribution ("CAFD") weighted average remaining contract life of approximately 18 years.

### Corporate Development

The Company's development activities for projects either owned directly by the Company or indirectly through AAGES entities are undertaken primarily by Abengoa-Algonquin Global Energy Solutions ("AAGES"), a joint venture with Abengoa S.A (MC: ABG) ("Abengoa"), an international infrastructure construction company. AAGES and its affiliates work with a global reach to identify, develop, and construct new renewable power generating facilities, power transmission lines, and water infrastructure assets. Once a project developed by AAGES has reached commercial operations ("COD"), APUC will work with AAGES to jointly determine whether it will be optimal for such project to be held by APUC, remain in AAGES, or be offered for sale to Atlantica or, in limited circumstances, another party.

# 2018 Major Highlights

## Corporate Highlights

**Operating Results**

APUC operating results relative to the same period last year are as follows:

| (all dollar amounts in $ millions except per share information) | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | 2018 | 2017 | Change |
| Net earnings attributable to shareholders | **$ 44.0** | $ 47.2 | **(7)%** | **$ 185.0** | $ 149.5 | **24%** |
| Adjusted Net Earnings[1] | **$ 70.5** | $ 67.0 | **5%** | **$ 312.2** | $ 225.0 | **39%** |
| Adjusted EBITDA[1] | **$ 196.9** | $ 185.8 | **6%** | **$ 803.3** | $ 689.4 | **17%** |
| Net earnings per common share | **$ 0.09** | $ 0.11 | **(18)%** | **$ 0.38** | $ 0.37 | **3%** |
| Adjusted Net Earnings per common share[1] | **$ 0.14** | $ 0.16 | **(13)%** | **$ 0.66** | $ 0.57 | **16%** |

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

**Declaration of 2019 First Quarter Dividend of $0.1282 ( C$0.1685) per Common Share**

APUC currently targets an industry leading annual growth in dividends payable to shareholders underpinned by increases in earnings and cashflow. In setting the appropriate dividend level, the Board of APUC considers the Company's current and expected growth in earnings per share as well as dividend payout ratio as a percentage of earnings per share and cash flow per share.

On February 28, 2019, APUC announced that the Board of APUC declared a first quarter 2019 dividend of $0.1282 per common share payable on April 15, 2019 to shareholders of record on March 29, 2019. Based on the Bank of Canada exchange rate on February 27, 2019, the Canadian dollar equivalent for the first quarter 2019 dividend is set at C$0.1685 per common share.

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

| | Q2 2018 | Q3 2018 | Q4 2018 | Q1 2019 | Total |
|---|---|---|---|---|---|
| U.S. dollar dividend | $ 0.1282 | $ 0.1282 | $ 0.1282 | $ 0.1282 | $ 0.5128 |
| Canadian dollar equivalent | $ 0.1648 | $ 0.1673 | $ 0.1679 | $ 0.1685 | $ 0.6685 |

**Completed formation of AAGES Joint Venture with Abengoa**

On March 9, 2018, APUC entered into an agreement to create AAGES, a joint venture with Abengoa S.A. ("Abengoa"), to identify, develop, and construct clean energy and water infrastructure assets.

**Investment in Atlantica**

In 2018, APUC purchased a 41.5% equity interest in Atlantica. Atlantica owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission, and water assets. The purchase was completed in two tranches.

On March 9, 2018, APUC acquired a 25% equity interest in Atlantica for a total purchase price of approximately $608 million, based on a price of $24.25 per ordinary share of Atlantica. On November 27, 2018, APUC purchased an additional 16.5% equity interest in Atlantica for a purchase price of approximately $345 million, based on a price of $20.90 per ordinary share of Atlantica.

The investment is expected to be immediately accretive to APUC's earnings and cash flows. The Company has included within its 2018 operating results $39.3 million of dividends received from Atlantica.

**Fitch Initiates First-Time Ratings to Algonquin Power & Utilities Corp. and Subsidiaries**

On July 20, 2018, Fitch Ratings, Inc. ("Fitch") assigned a BBB Long-Term Issuer Default Rating ("IDR") and an F2 Short-Term IDR to APUC and Liberty Utilities Co. ("LUCo"), the parent company for the Liberty Utilities Group. Fitch assigned a BBB Long-Term IDR and an F3 Short-Term IDR to Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group. The rating outlook for each entity is stable. Fitch also assigned a BBB+ rating to the senior unsecured debt issued by Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of LUCo. See *Treasury Risk Management- Downgrade in the Company's Credit Rating Risk*.

**DBRS Upgrades APUC and APCo Issuer Ratings to BBB with a Stable Trend**

Subsequent to year end, DBRS Limited ("DBRS") upgraded the issuer rating of APUC and APCo to BBB with a stable trend and APUC's preferred share rating to Pfd-3. The APCo upgrade reflects the agency's view of increased scale and a solid business risk profile resulting from long term contracted power assets. The APUC rating upgrade reflects the agency's view of a significant improvement in the Company's business risk profile following the acquisition and successful integration of The Empire District Electric Company ("Empire") as well as strong cash flows underpinned by regulated operations and contracted power assets.

**Corporate Financings Completed**

*C$444.4 Million Common Equity Financing*

On April 24, 2018, APUC closed the sale of approximately 37.5 million of its common shares to certain institutional investors at a price of C$11.85 per share, for gross proceeds of approximately C$444.4 million. The proceeds of the offering were used to pay down existing indebtedness and to fund in part the purchase of the additional 16.5% interest in Atlantica.

*Issuance of Fixed-to-Floating Subordinated Notes*

On October 17, 2018, APUC issued $287.5 million of 60 (non-call 5) year fixed-to-floating 6.875% subordinated notes. The offering represents APUC's inaugural entry into the U.S. public debt markets (see *Long Term Debt*).

*C$172.5 Million Common Equity Financing*

On December 20, 2018, APUC closed the sale of approximately 12.5 million of its common shares to certain institutional investors at a price of C$13.76 per share, for gross proceeds of approximately C$172.5 million. The proceeds of the offering will be used to partially finance the acquisition of Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas") (*see Major Highlights - Liberty Utilities)*, and for general corporate purposes.

**Change to U.S. Dollar Reporting**

Effective the first quarter of 2018, APUC's interim and annual consolidated financial statements are now reported in U.S. dollars.

Over 90% of APUC's consolidated revenue, EBITDA and assets are derived from operations in the United States. In addition, APUC's dividend is denominated in U.S. dollars and the Company's common shares are listed on the New York Stock Exchange. The Company believes that the change in reporting to U.S. dollars provides improved information to investors and allow for better assessment of its results without the effects of the change in currency on 90% of its operations.

## Liberty Utilities Group Highlights

**Successful Rate Review Outcomes**

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2018 and 2019 year to date, the Liberty Utilities Group successfully completed several rate reviews representing a cumulative annualized revenue increase of approximately $24.5 million. In addition progress was made in advancing several regulatory mechanisms. In New Hampshire and Missouri the Public Utilities Commissions approved revenue decoupling as part of their orders.

*Resolution with Regulators Regarding the Impacts of Tax Reform*

On December 22, 2017, the Tax Cuts and Jobs Act ("U.S. Tax Reform") was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, U.S. Tax Reform reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates has impacted regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. Throughout the course of 2018, the Liberty Utilities Group obtained orders from the majority of its principal regulators covering approximately 93% of customers, resulting in the reduction of customer rates in connection with the reduction in tax rates. Collectively, the orders represent an annualized aggregate reduction in utility revenues of approximately $35 million, of which approximately $18 million has been realized in 2018.

**Progress Made on Customer Savings Plan**

In 2017, Empire proposed to its regulators in Missouri, Kansas, Oklahoma, and Arkansas a Customer Savings Plan which would phase out its Asbury Coal Generation Facility and develop additional wind generation in or near its service territory that will utilize all available Production Tax Credits. The plan calls for the development of up to 600 MW of sustainable, cost-effective wind power to serve the needs of electricity customers within the Liberty Utilities Group's Midwest electric service territory and forecasts cost savings for customers of approximately $169 million and $325 million over a 20-year and 30-year period, respectively.

On July 11, 2018, Empire received an order from the Missouri Public Service Commission ("MPSC") supporting various requests related to its proposed plan, which has allowed the Liberty Utilities Group to continue to pursue the development of up to 600 MW of wind power and recognizes that "millions of dollars of customer savings could be of considerable benefit to Empire's customers and the entire state".

On October 18, 2018, and November 18, 2018, Empire filed with the MPSC a request for Certificates of Convenience and Necessity ("CCN"), in each case for 300 MW of the 600 MW contemplated as part of the initiative. A final hearing on the merits is scheduled for April 2019.

**Acquisition of New Brunswick Gas**

On December 4, 2018, the Liberty Utilities Group announced that it entered into an agreement to purchase New Brunswick Gas. New Brunswick Gas is a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick, and operates approximately 800 km of natural gas distribution pipeline. The total purchase price for the transaction is C$331 million, subject to customary adjustments. The transaction closing is expected in 2019, following regulatory approvals.

**Acquisition of Ownership Interest in Wataynikaneyap Power Transmission Project**

Subsequent to year-end on January 17, 2019, the Liberty Utilities Group acquired from Fortis Inc. a 9.8% ownership interest in an electricity transmission project located in Northwestern Ontario (the "Wataynikaneyap Power Transmission Project") that is expected to connect 17 remote First Nation communities to the Ontario provincial electricity grid through the construction of approximately 1,800 km of transmission lines. In addition to providing participating First Nations communities ownership in the transmission line, the Wataynikaneyap Power Transmission Project is expected to result in socio-economic benefits for surrounding communities, reduce environmental risk and lessen greenhouse gas emissions associated with diesel-fired generation currently used in the area.

## Liberty Power Group Highlights

**Completion of the Great Bay Solar Project**

On March 29, 2018, the Great Bay Solar Facility achieved COD. The facility consists of a 75 MW solar powered electric generating facility comprised of four sites located in Somerset County in southern Maryland. The Great Bay Solar Facility is the Liberty Power Group's fourth solar generating facility and consists of 300,000 solar panels and is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year Power Purchase Agreement ("PPA"), with a 10 year extension option.

**Completion of the Amherst Island Wind Project**

On June 15, 2018, the Amherst Island Wind Facility achieved COD. The facility consists of a 75 MW wind powered electric generating facility located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario. The Amherst Island Wind Facility is the Liberty Power Group's 12th wind powered electric generating facility and is comprised of 26 Siemens 3.2 MW turbines and is expected to generate approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold to the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority.

**Issuance of Green Bonds**

Subsequent to year-end on January 29, 2019, the Liberty Power Group issued C$300.0 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures represent Liberty Power Group's inaugural "green bond" offering (see *Long Term Debt*).

## 2018 Fourth Quarter Results From Operations

### Key Financial Information

| (all dollar amounts in $ millions except per share information) | Three Months Ended December 31 2018 | 2017 |
|---|---|---|
| Revenue | **$ 419.9** | $ 409.5 |
| Net earnings attributable to shareholders | **44.0** | 47.2 |
| Cash provided by operating activities | **168.6** | 116.0 |
| Adjusted Net Earnings[1] | **70.5** | 67.0 |
| Adjusted EBITDA[1] | **196.9** | 185.8 |
| Adjusted Funds from Operations[1] | **132.5** | 126.0 |
| Dividends declared to common shareholders | **63.1** | 50.5 |
| Weighted average number of common shares outstanding | **477,450,181** | 412,632,308 |
| **Per share** | | |
| Basic net earnings | **$ 0.09** | $ 0.11 |
| Diluted net earnings | **$ 0.09** | $ 0.11 |
| Adjusted Net Earnings[1,2] | **$ 0.14** | $ 0.16 |
| Dividends declared to common shareholders | **$ 0.13** | $ 0.12 |

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

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

For the three months ended December 31, 2018, APUC experienced an average exchange rate of Canadian to U.S. dollar of approximately 0.7568 as compared to 0.7865 in the same period in 2017. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's Canadian entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2018, APUC reported total revenue of $419.9 million as compared to $409.5 million during the same period in 2017, an increase of $10.4 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2018 as compared to the corresponding period in 2017 are set out as follows:

| (all dollar amounts in $ millions) | | Three Months Ended December 31 |
|---|---|---|
| **Comparative Prior Period Revenue** | **$** | **409.5** |
| **LIBERTY UTILITIES GROUP** | | |
| **Existing Facilities** | | |
| Electricity: Increase is primarily due to higher heating degree days, which resulted in higher consumption at the Empire Electric System. | | 10.7 |
| Gas: Increase is primarily due to higher consumption and pass through commodity costs at the Midstates, New England, Empire and EnergyNorth Gas Systems due to higher heating degree days. | | 6.6 |
| Water: Decrease is primarily due to lower consumption at the Arkansas Water System and lower phased-in revenue at the White Hall Water system. | | (0.4) |
| Other | | (0.2) |
| | | **16.7** |
| **Rate Reviews** | | |
| Electricity: Implementation of lower rates at the Granite State and Empire Electric systems due to U.S. Tax reform, partially offset by rate increases at the Calpeco Electric System. | | (4.4) |
| Gas: Implementation of new rates, partially offset by U.S. Tax Reform impact, primarily at Midstates and EnergyNorth Gas Systems. | | 1.7 |
| Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform. | | (0.7) |
| | | **(3.4)** |
| **LIBERTY POWER GROUP** | | |
| **Existing Facilities** | | |
| Hydro: Increase is primarily due to higher production and favourable rates in the Western Region partially offset by unfavourable rates in the Maritime Region. | | 0.9 |
| Wind Canada: Decrease is primarily due to lower production. | | (2.6) |
| Wind U.S.: Decrease is primarily due to lower production. | | (3.4) |
| Solar Canada: Decrease is primarily due to lower production. | | (0.1) |
| Solar U.S.: Decrease is primarily due to lower production. | | (0.2) |
| Thermal: Increase is primarily due to higher production and an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018. | | 1.2 |
| Other | | 0.4 |
| | | **(3.8)** |
| **New Facilities** | | |
| Solar US: Great Bay Solar Facility achieved full COD in March 2018. | | 1.7 |
| | | **1.7** |
| **Foreign Exchange** | | **(0.8)** |
| **Current Period Revenue** | **$** | **419.9** |

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

For the three months ended December 31, 2018, net earnings attributable to shareholders totaled $44.0 million as compared to $47.2 million during the same period in 2017, a decrease of $3.2 million or 6.8%. The decrease was due to a $10.2 million decrease in earnings from operating facilities, $46.0 million loss due to change in fair value of an investment carried at fair value, $6.9 million increase in interest expense, $0.3 million increase in administration charges and a $2.8 million decrease in gains from derivative instruments. These items were partially offset by a $9.9 million decrease in acquisition related costs, $5.4 million decrease in depreciation and amortization expenses, $0.6 million increase in foreign exchange gain, a $1.1 million decrease in pension and post-employment non-service costs, $17.5 million increase in interest, dividend, equity and other income primarily from the investment in Atlantica, $1.4 million increase in other gains, $0.2 million increase in net effect of non-controlling interests, and a $26.9 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2017.

During the three months ended December 31, 2018, cash provided by operating activities totaled $168.6 million as compared to $116.0 million during the same period in 2017. During the three months ended December 31, 2018, Adjusted Funds from Operations totaled $132.5 million as compared to $126.0 million during the same period in 2017.

During the three months ended December 31, 2018, Adjusted EBITDA totaled $196.9 million as compared to $185.8 million during the same period in 2017, an increase of $11.1 million or 6.0%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

## 2018 Annual Results From Operations

### Key Financial Information

| (all dollar amounts in $ millions except per share information) | Twelve Months Ended December 31 2018 | 2017 | 2016 |
|---|---|---|---|
| Revenue | **$ 1,647.4** | $ 1,521.9 | $ 823.0 |
| Net earnings attributable to shareholders | **185.0** | 149.5 | 97.9 |
| Cash provided by operating activities | **530.4** | 326.6 | 229.5 |
| Adjusted Net Earnings[1] | **312.2** | 225.0 | 121.4 |
| Adjusted EBITDA[1] | **803.3** | 689.4 | 358.9 |
| Adjusted Funds from Operations[1] | **554.1** | 477.1 | 267.9 |
| Dividends declared to common shareholders | **235.4** | 185.9 | 113.2 |
| Weighted average number of common shares outstanding | **461,818,023** | 382,323,434 | 271,832,430 |
| **Per share** | | | |
| Basic net earnings | **$ 0.38** | $ 0.37 | $ 0.33 |
| Diluted net earnings | **$ 0.38** | $ 0.37 | $ 0.33 |
| Adjusted Net Earnings[1,2] | **$ 0.66** | $ 0.57 | $ 0.42 |
| Dividends declared to common shareholders | **$ 0.50** | $ 0.47 | $ 0.41 |
| Total assets | **9,389.0** | 8,395.6 | 6,143.9 |
| Long term debt[3] | **3,337.3** | 3,080.5 | 3,181.7 |

[1] See Non-GAAP Financial Measures.

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

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

For the twelve months ended December 31, 2018, APUC experienced an average exchange rate of Canadian to U.S. of approximately 0.7715 as compared to 0.7705 in the same period in 2017. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's Canadian entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2018, APUC reported total revenue of $1,647.4 million as compared to $1,521.9 million during the same period in 2017, an increase of $125.5 million or 8.2%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2018 as compared to the corresponding period in 2017 are set out as follows:

| (all dollar amounts in $ millions) | | Twelve Months Ended December 31 |
|---|---|---|
| **Comparative Prior Period Revenue** | **$** | **1,521.9** |
| **LIBERTY UTILITIES GROUP** | | |
| **Existing Facilities** | | |
| Electricity: Increase is primarily due to higher heating degree days in the first & fourth quarters, and higher cooling degree days in the second & third quarters of the year, which resulted in higher consumption and pass through commodity costs at the Empire Electric System. | | 71.4 |
| Gas: Increase is primarily due to favourable weather resulting in higher consumption and higher pass through commodity costs at the Midstates, EnergyNorth, New England and Empire Gas Systems. | | 48.1 |
| Water: Decrease is primarily due to divestiture of the Mountain Water System from condemnation proceedings on June 22, 2017. | | (10.4) |
| Other | | (0.3) |
| | | **108.8** |
| **Rate Reviews** | | |
| Electricity: Implementation of lower rates at the Empire Electric System due to U.S. Tax Reform, partially offset by rate increases at the Calpeco Electric System. | | (3.7) |
| Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at the Midstates and EnergyNorth Gas Systems. | | 5.4 |
| Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform. | | (1.3) |
| | | **0.4** |
| **LIBERTY POWER GROUP** | | |
| **Existing Facilities** | | |
| Hydro: Decrease is primarily due to lower production and the recognition of a bonus payment from Hydro Quebec in the prior year, partially offset by favourable rates in the Western Region. | | (2.5) |
| Wind Canada: Decrease is primarily due to lower overall production. | | (2.5) |
| Wind U.S.: Decrease is primarily due to lower production and unfavourable market rates at the Senate Wind Facility, partially offset by favourable market rates at the Shady Oaks, Sandy Ridge and Minonk Wind Facilities. | | (5.5) |
| Solar Canada: Increase is primarily due to higher production. | | 0.1 |
| Thermal: Increase is primarily due to higher overall production as well as an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018. | | 12.1 |
| Other: Increase is primarily due to higher management fee from managed companies. | | 0.8 |
| | | **2.5** |
| **New Facilities** | | |
| Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017. | | 6.0 |
| Solar U.S.: Great Bay Solar Facility reached full COD in March 2018. | | 7.6 |
| | | **13.6** |
| **Foreign Exchange** | | **0.2** |
| **Current Period Revenue** | **$** | **1,647.4** |

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

For the twelve months ended December 31, 2018, net earnings attributable to shareholders totaled $185.0 million as compared to $149.5 million during the same period in 2017, an increase of $35.5 million. The increase was due to a $12.4 million increase in earnings from operating facilities, $43.9 million increase in interest, dividend, equity and other income received primarily from the investment in Atlantica, $47.0 million decrease in acquisition costs, $58.1 million increase in net effect of non-controlling interests, $0.4 million increase in foreign exchange gain, $3.7 million decrease in interest expense, a $5.1 million decrease in pension and post-employment non-service costs, and a $20.0 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*). These items were partially offset by a $138.0 million loss due to change in fair value of an investment carried at fair value, $3.1 million increase in administration charges, $9.5 million increase in depreciation and amortization expenses, $2.0 million increase in other losses, and a $2.5 million decrease on gains from derivative instruments.

During the twelve months ended December 31, 2018, cash provided by operating activities totaled $530.4 million as compared to $326.6 million during the same period in 2017. During the twelve months ended December 31, 2018, Adjusted Funds from Operations, a non-GAAP measure, totaled $554.1 million as compared to $477.1 million the same period in 2017, an increase of $77.0 million.

Adjusted EBITDA in the twelve months ended December 31, 2018 totaled $803.3 million as compared to $689.4 million during the same period in 2017, an increase of $113.9 million or 16.5%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

## 2018 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2018 totaled $196.9 million as compared to $185.8 million during the same period in 2017, an increase of $11.1 million or 6.0%. Adjusted EBITDA for the twelve months ended December 31, 2018 totaled $803.3 million as compared to $689.4 million during the same period in 2017, an increase of $113.9 million or 16.5%. The breakdown of Adjusted EBITDA by the Company's main operating segments and a summary of changes are shown below.

| **Adjusted EBITDA by business units** | **Three Months Ended December 31** | | **Twelve Months Ended December 31** | |
|---|---|---|---|---|
| **(all dollar amounts in $ millions)** | **2018** | **2017** | **2018** | **2017** |
| Liberty Utilities Group Operating Profit | **$ 132.9** | $ 144.4 | **$ 550.5** | $ 544.2 |
| Liberty Power Group Operating Profit | **78.7** | 55.7 | **303.6** | 192.8 |
| Administrative Expenses | **(15.0)** | (14.7) | **(52.7)** | (49.6) |
| Other Income & Expenses | **0.3** | 0.4 | **1.9** | 2.0 |
| **Total Algonquin Power & Utilities Adjusted EBITDA** | **$ 196.9** | $ 185.8 | **$ 803.3** | $ 689.4 |
| Change in Adjusted EBITDA ($) | **$ 11.1** | | **$ 113.9** | |
| Change in Adjusted EBITDA (%) | **6.0%** | | **16.5%** | |

| **Change in Adjusted EBITDA** | **Three Months Ended December 31, 2018** | | | |
|---|---|---|---|---|
| **(all dollar amounts in $ millions)** | **Utilities** | **Power** | **Corporate** | **Total** |
| **Prior period balances** | **$ 144.4** | **$ 55.7** | **$ (14.3)** | **$ 185.8** |
| Existing Facilities | (8.1) | 0.6 | (0.1) | (7.6) |
| New Facilities | — | 23.0 | — | 23.0 |
| Rate Reviews | (3.4) | — | — | (3.4) |
| Foreign Exchange Impact | — | (0.6) | — | (0.6) |
| Administrative Expenses | — | — | (0.3) | (0.3) |
| **Total change during the period** | **$ (11.5)** | **$ 23.0** | **$ (0.4)** | **$ 11.1** |
| **Current period balances** | **$ 132.9** | **$ 78.7** | **$ (14.7)** | **$ 196.9** |

| **Change in Adjusted EBITDA** | **Twelve Months Ended December 31, 2018** | | | |
|---|---|---|---|---|
| **(all dollar amounts in $ millions)** | **Utilities** | **Power** | **Corporate** | **Total** |
| **Prior period balances** | **$ 544.2** | **$ 192.8** | **$ (47.6)** | **$ 689.4** |
| Existing Facilities | 5.9 | 45.0 | (0.1) | 50.8 |
| New Facilities | — | 65.9 | — | 65.9 |
| Rate Reviews | 0.4 | — | — | 0.4 |
| Foreign Exchange Impact | — | (0.1) | — | (0.1) |
| Administration Expenses | — | — | (3.1) | (3.1) |
| **Total change during the period** | **$ 6.3** | **$ 110.8** | **$ (3.2)** | **$ 113.9** |
| **Current period balances** | **$ 550.5** | **$ 303.6** | **$ (50.8)** | **$ 803.3** |

## LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 768,000 connections in the natural gas, electric, water and wastewater sectors which is an increase of 6,000 connections as compared to the prior year resulting primarily from organic growth in the Liberty Utilities Group's service territories. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing connections in the communities in which it operates.

### Utility System Type

| | As at December 31 | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| (all dollar amounts in $ millions) | Assets | Total Connections[1] | Assets | Total Connections[1] |
| Electricity | **$ 2,578.7** | **266,000** | $ 2,479.9 | 265,000 |
| Natural Gas | **1,057.3** | **338,000** | 996.1 | 337,000 |
| Water and Wastewater | **481.4** | **164,000** | 462.6 | 160,000 |
| **Total** | **$ 4,117.4** | **768,000** | $ 3,938.6 | 762,000 |
| Accumulated Deferred Income Taxes Liability | **$ 438.4** | | $ 392.8 | |

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

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

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 266,000 connections in the states of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 338,000 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 164,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri and Texas.

### 2018 Annual Usage Results

### Electric Distribution Systems

| | Three Months Ended December 31 | | Twelve Months Ended December 31 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| **Average Active Electric Connections For The Period** | | | | |
| Residential | **225,900** | 224,400 | **225,200** | 223,700 |
| Commercial and industrial | **37,900** | 39,200 | **37,800** | 39,200 |
| **Total Average Active Electric Connections For The Period** | **263,800** | 263,600 | **263,000** | 262,900 |
| **Customer Usage (GW-hrs)** | | | | |
| Residential | **611.2** | 571.7 | **2,535.1** | 2,320.1 |
| Commercial and industrial | **971.2** | 882.3 | **3,988.9** | 3,523.1 |
| **Total Customer Usage (GW-hrs)** | **1,582.4** | 1,454.0 | **6,524.0** | 5,843.2 |

For the three months ended December 31, 2018, the electric distribution systems' usage totaled 1,582.4 GW-hrs as compared to 1,454.0 GW-hrs for the same period in 2017, an increase of 128.4 GW-hrs or 8.8%, primarily due to higher heating degree days at the Empire Electric System.

For the twelve months ended December 31, 2018, the electric distribution systems' usage totaled 6,524.0 GW-hrs as compared to 5,843.2 GW-hrs for the same period in 2017, an increase of 680.8 GW-hrs or 11.7%. The increase is primarily due to higher heating degree days in the first and fourth quarters and higher cooling degree days in the second and third quarters at the Empire Electric System.

## Natural Gas Distribution Systems

| | Three Months Ended December 31 | | Twelve Months Ended December 31 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| **Average Active Natural Gas Connections For The Period** | | | | |
| Residential | **288,900** | 286,700 | **288,700** | 287,100 |
| Commercial and industrial | **31,700** | 31,700 | **31,700** | 31,700 |
| **Total Average Active Natural Gas Connections For The Period** | **320,600** | 318,400 | **320,400** | 318,800 |
| | | | | |
| **Customer Usage (MMBTU)** | | | | |
| Residential | **6,186,000** | 5,196,000 | **20,065,000** | 17,621,000 |
| Commercial and industrial | **4,533,000** | 4,282,000 | **14,529,000** | 12,672,000 |
| **Total Customer Usage (MMBTU)** | **10,719,000** | 9,478,000 | **34,594,000** | 30,293,000 |

For the three months ended December 31, 2018, usage at the natural gas distribution systems totaled 10,719,000 MMBTU as compared to 9,478,000 MMBTU during the same period in 2017, an increase of 1,241,000 MMBTU, or 13.1%. The increase is primarily due to higher heating degree days across all of the gas systems.

For the twelve months ended December 31, 2018, usage at the natural gas distribution systems totaled 34,594,000 MMBTU as compared to 30,293,000 MMBTU during the same period in 2017, an increase of 4,301,000 MMBTU or 14.2%. The increase is primarily due to higher heating degree days at the Midstates, Peach State and Empire Gas Systems.

## Water and Wastewater Distribution Systems

| | Three Months Ended December 31 | | Twelve Months Ended December 31 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| **Average Active Connections For The Period** | | | | |
| Wastewater connections | **43,000** | 41,400 | **42,200** | 41,000 |
| Water distribution connections | **113,200** | 111,800 | **112,800** | 121,400 |
| **Total Average Active Connections For The Period** | **156,200** | 153,200 | **155,000** | 162,400 |
| | | | | |
| **Gallons Provided** | | | | |
| Wastewater treated (millions of gallons) | **606** | 555 | **2,282** | 2,226 |
| Water provided (millions of gallons) | **3,655** | 3,909 | **15,823** | 16,905 |
| **Total Gallons Provided** | **4,261** | 4,464 | **18,105** | 19,131 |

During the three months ended December 31, 2018, the water and wastewater distribution systems provided approximately 3,655 million gallons of water to its customers and treated approximately 606 million gallons of wastewater as compared to 3,909 million gallons of water provided and 555 million gallons of wastewater treated during the same period in 2017.

During the twelve months ended December 31, 2018, the water and wastewater distribution systems provided approximately 15,823 million gallons of water to its customers and treated approximately 2,282 million gallons of wastewater as compared to 16,905 million gallons of water and 2,226 million gallons of wastewater during the same period in 2017. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana in the second quarter of 2017. Excluding the Mountain Water System, the volumes of water provided to customers were relatively flat year-over-year.

## 2018 Liberty Utilities Group Operating Results

| | Three Months Ended December 31 | | Twelve Months Ended December 31 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| **Revenue** | | | | |
| Utility electricity sales and distribution | **$ 193.2** | $ 187.0 | **$ 831.2** | $ 763.5 |
| Less: cost of sales – electricity | **(63.4)** | (51.6) | **(265.1)** | (222.4) |
| Net Utility Sales - electricity[1] | **129.8** | 135.4 | **566.1** | 541.1 |
| Utility natural gas sales and distribution | **115.5** | 108.0 | **395.5** | 344.2 |
| Less: cost of sales – natural gas | **(59.0)** | (53.1) | **(183.0)** | (141.7) |
| Net Utility Sales - natural gas[1] | **56.5** | 54.9 | **212.5** | 202.5 |
| Utility water distribution & wastewater treatment sales and distribution | **30.4** | 31.5 | **128.4** | 140.1 |
| Less: cost of sales – water | **(2.1)** | (2.4) | **(8.8)** | (9.5) |
| Net Utility Sales - water distribution & wastewater treatment [1] | **28.3** | 29.1 | **119.6** | 130.6 |
| Gas transportation | **10.4** | 9.6 | **33.4** | 31.2 |
| Other revenue | **4.8** | 5.1 | **11.6** | 11.8 |
| **Net Utility Sales**[1] | **229.8** | 234.1 | **943.2** | 917.2 |
| Operating expenses | **(99.0)** | (92.4) | **(401.5)** | (383.4) |
| Other income | **1.5** | 1.4 | **5.6** | 4.2 |
| HLBV[2] | **0.6** | 1.3 | **3.2** | 6.2 |
| **Divisional Operating Profit[1,3]** | **$ 132.9** | $ 144.4 | **$ 550.5** | $ 544.2 |

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

[2] HLBV income represents the value of net tax attributes earned by the Liberty Utilities Group in the period primarily from electricity generated at the Luning Solar Facility.

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

## 2018 Fourth Quarter Operating Results

For the three months ended December 31, 2018, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of $132.9 million as compared to $144.4 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

| (all dollar amounts in $ millions) | | Three Months Ended December 31 |
|---|---|---|
| **Prior Period Operating Profit** | **$** | **144.4** |
| **Existing Facilities** | | |
| Electricity: Decrease is primarily due to higher commodity costs combined with higher operating costs at the Empire and Granite State Electric Systems. | | (10.3) |
| Gas: Increase is primarily due to operating cost savings at the New England Gas System. | | 3.2 |
| Water: Decrease is primarily due to increase in operating costs at the Arizona and Whitehall Water Systems. | | (0.1) |
| Other | | (0.9) |
| | | **(8.1)** |
| **Rate Reviews** | | |
| Electricity: Implementation of lower rates at the Granite State and Empire Electric Systems due to U.S. Tax reform, partially offset by rate increases at the Calpeco Electric System. | | (4.4) |
| Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at Midstates and EnergyNorth Gas Systems. | | 1.7 |
| Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform. | | (0.7) |
| | | **(3.4)** |
| **Current Period Divisional Operating Profit[1]** | **$** | **132.9** |

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

## 2018 Annual Operating Results

For the twelve months ended December 31, 2018, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of $550.5 million as compared to $544.2 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 |
|---|---|---|
| **Prior Period Operating Profit** | **$** | **544.2** |
| **Existing Facilities** | | |
| Electricity: Increase is primarily due to higher heating degree days in the first and fourth quarters and higher cooling degree days in the second & third quarters of the year, which resulted in higher consumption at the Empire Electric System, partially offset by an increase in operating costs. | | 8.9 |
| Gas: Increase is primarily due to favourable weather resulting in higher consumption at the Empire Gas and New England Gas Systems, partially offset by an increase in operating costs at the EnergyNorth Gas System. | | 2.5 |
| Water: Decrease is primarily due to lower revenue resulting from the disposition of the Mountain Water System in Montana as well as higher operating costs. | | (6.0) |
| Other | | 0.5 |
| | | **5.9** |
| **Rate Reviews** | | |
| Electricity: Implementation of lower rates at the Empire Electric System due to U.S. Tax Reform, partially offset by rate increases at the Calpeco Electric System. | | (3.7) |
| Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at the Midstates and EnergyNorth Gas Systems. | | 5.4 |
| Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform. | | (1.3) |
| | | **0.4** |
| **Current Period Divisional Operating Profit[1]** | **$** | **550.5** |

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

## Regulatory Proceedings

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

| Utility | State | Regulatory Proceeding Type | | Rate Request (millions) | Current Status |
|---|---|---|---|---|---|
| **Completed Rate Reviews** | | | | | |
| EnergyNorth Gas System | New Hampshire | General Rate Case ("GRC") | $ | 19.5 | In April 2018, an Order was issued approving a full revenue decoupling mechanism and an immediate revenue increase of $13.1 million effective May 1, 2018 and the ability to collect an additional $0.4 million in the cost of gas filing. In total, this represents revenue increases of $13.5 million. Concurrent with the implementation of these new rates, the New Hampshire Public Utilities Commission ("NHPUC") also ordered a reduction in rates of $2.4 million resulting from U.S. Tax Reform which will be reflected in EnergyNorth's future rates effective May 1, 2018, bringing the net rate increase to $11.1 million. |
| New England Gas | Massachusetts | Gas System Enhancement Plan ("GSEP") | $ | 5.8 | Final Order issued in April 2018 approving a $3.7 million rate increase effective May 1, 2018. |
| Missouri Gas System | Missouri | GRC | $ | 6.0 | Final Order issued in June 2018 approving a $4.6 million rate increase effective July 1, 2018 and a revenue decoupling mechanism for residential and small commercial customers. |
| Peach State Gas System | Georgia | GRAM | $ | 2.4 | On January 31, 2019, an Order was issued approving an increase in revenue of $2.4 million for rates effective February 1, 2019. |
| Empire Electric System | Missouri | Tax Cuts and Jobs Act of 2017 | $ | -17.8 | Prospective decrease in annual revenue of $17.8 million due to U.S. Tax Reform beginning August 30, 2018. |
| Various | Various | Various | $ | 4.8 | Rate reviews closed in 2018 with a combined approved rate increase of $3.0 million include: Park Water 2018 increase, Georgia Gas Rate Adjustment Mechanism, Missouri Water System, and Litchfield Park Water & Sewer. |
| **Pending Rate Reviews** | | | | | |
| CalPeco Electric | California | GRC | $ | 6.7 | On December 3, 2018, filed a three year application requesting a rate increase of $6.7 million for 2019 ($5.9 million for 2020 and $3.8 million for 2021). |
| Empire Electricity (Kansas System) | Kansas | GRC | $ | 2.5 | On December 7, 2018, filed an application requesting an incremental increase in revenue requirement of $2.5 million. |
| New England Natural Gas System | Massachusetts | GSEP | $ | 3.8 | On October 31, 2018, filed for an incremental increase in revenue requirement of $3.8 million for the 2019 GSEP. |
| Various | Various | Various | $ | 3.9 | Other pending rate review requests include: Woodmark/Tall Timbers Wastewater Systems ($1.6 million), Silverleaf Texas Water and Wastewater Systems ($1.3 million), and Apple Valley and Park Water Systems ($1.0 million). |

**Completed Rate Reviews**

*New Hampshire*

On April 28, 2017, the Liberty Utilities Group filed a distribution rate application with the NHPUC, for rates to be effective May 1, 2018, seeking a total revenue increase of $19.5 million with approximately $14.5 million based on a test year ending December 31, 2016 plus a step increase of approximately $5.0 million. Temporary rates of $7.8 million to be effective July 1, 2017, and full revenue decoupling from the impacts of weather were requested. On June 30, 2017, the NHPUC approved temporary rates of $6.8 million effective July 1, 2017 to be in place until the end of the permanent rate case. On April 27, 2018, the NHPUC issued its Order approving a full revenue decoupling mechanism and an immediate revenue increase of $13.1 million effective May 1, 2018 and the ability to collect an additional $0.4 million in the cost of gas filing. In total, this represents revenue increases of $13.5 million (70% of the requested increase amount). Concurrent with the implementation of these new rates, the NHPUC has also ordered a reduction in rates of $2.4 million resulting from U.S. Tax Reform which will be reflected in the EnergyNorth Gas System's future rates effective May 1, 2018, bringing the net rate increase to $11.1 million. The order also authorizes an ROE of 9.3% and an additional one-time, $1.3 million recoupment to be collected from customers to make whole the difference between the permanent rates and the temporary rates authorized on July 1, 2017. In May 2018, EnergyNorth filed a motion for rehearing to clarify the implementation date of the decoupling mechanism that was approved. In addition, the NHPUC resolved the impacts of tax reform through the rehearing instead of addressing it in a separate hearing. The net result was a one-time decrease in revenue of $0.3 million.

*Massachusetts*

On October 31, 2017, Liberty Utilities (New England Natural Gas Company) Corp. filed its 2018 GSEP application requesting recovery of $6.2 million for replacement of approximately 14 miles of eligible infrastructure. In March 2018, the revenue requirement was revised to $5.8 million. On April 30, 2018 an order was issued authorizing the recovery of $3.7 million. The revenue increase is not affected by U.S. Tax Reform but is expected to be addressed in the 2019 filing.

*Missouri*

On September 29, 2017, Liberty Utilities (Midstates Natural Gas) Corp. filed an application seeking a rate increase of $7.5 million for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. In April 2018, the revenue requirement request was revised to $6.0 million. An order was issued on June 6, 2018 authorizing an annual revenue increase of $4.6 million, a 9.8% ROE, and also incorporates the effects of U.S. Tax Reform. The order contemplates that new rates will go into effect on July 1, 2018. In addition, it adopts rate consolidation for the NEMO and WEMO districts, and allows the Liberty Utilities Group to adopt a Weather Normalization Adjustment Rider designed to adjust the Company's rates for the impact of weather on customer usage.

On July 12, 2018, Empire received an order from the MPSC supporting various requests related to its proposed Customer Savings Plan, which calls for the development of up to 600 MW of sustainable, cost-effective wind power to serve the needs of electricity customers within the Liberty Utilities Group's Midwest electric service territory. The order allows the Liberty Utilities Group to continue to pursue the development of up to 600 MW of wind and recognizes that "millions of dollars of customer savings could be of considerable benefit to Empire's customers and the entire state". In addition, regulatory proceedings in other jurisdictions will be completed as necessary. The Company has filed CCN applications with the MPSC for the North Fork Ridge, Kings Point and Neosho Ridge Wind Projects and a final hearing has been scheduled for April 2019. The Company has also filed a CCN application with the Kansas Corporation Commission for the gen-tie line associated with the Neosho Ridge Wind Project.

## LIBERTY POWER GROUP

### 2018 Electricity Generation Performance

| (Performance in GW-hrs sold) | Long Term Average Resource | Three Months Ended December 31 2018 | 2017 | Long Term Average Resource | Twelve Months Ended December 31 2018 | 2017 |
|---|---|---|---|---|---|---|
| **Hydro Facilities:** | | | | | | |
| Maritime Region | **37.6** | **31.4** | 34.9 | **148.2** | **107.5** | 129.7 |
| Quebec Region | **72.6** | **73.6** | 67.5 | **273.3** | **263.7** | 270.6 |
| Ontario Region | **26.2** | **31.3** | 30.6 | **120.4** | **106.5** | 129.5 |
| Western Region | **12.6** | **11.2** | 10.5 | **65.0** | **59.8** | 59.6 |
| | **149.0** | **147.5** | 143.5 | **606.9** | **537.5** | 589.4 |
| **Wind Facilities:** | | | | | | |
| St. Damase | **22.7** | **22.2** | 24.0 | **76.9** | **78.8** | 74.3 |
| St. Leon | **121.4** | **101.4** | 138.7 | **430.2** | **394.8** | 444.2 |
| Red Lily[1] | **24.1** | **20.0** | 29.2 | **88.5** | **81.3** | 91.6 |
| Morse | **30.5** | **26.2** | 33.1 | **108.8** | **96.8** | 106.4 |
| Amherst[2] | **67.9** | **58.7** | — | **118.5** | **105.7** | — |
| Sandy Ridge | **43.6** | **43.8** | 42.0 | **158.3** | **152.2** | 153.3 |
| Minonk | **189.8** | **173.8** | 203.5 | **673.7** | **611.3** | 673.7 |
| Senate | **140.0** | **125.2** | 126.6 | **520.4** | **484.9** | 492.8 |
| Shady Oaks | **100.5** | **91.5** | 108.7 | **355.6** | **326.6** | 365.5 |
| Odell | **238.0** | **199.9** | 244.6 | **831.8** | **759.4** | 807.2 |
| Deerfield[3] | **167.9** | **153.8** | 164.3 | **546.0** | **531.2** | 449.3 |
| | **1,146.4** | **1,016.5** | 1,114.7 | **3,908.7** | **3,623.0** | 3,658.3 |
| **Solar Facilities:** | | | | | | |
| Cornwall | **2.2** | **1.8** | 2.1 | **14.7** | **14.5** | 14.4 |
| Bakersfield | **13.0** | **9.5** | 12.7 | **77.2** | **70.0** | 70.5 |
| Great Bay Solar[4] | **25.7** | **26.4** | — | **115.6** | **110.6** | — |
| | **40.9** | **37.7** | 14.8 | **207.5** | **195.1** | 84.9 |
| **Renewable Energy Performance** | **1,336.3** | **1,201.7** | 1,273.0 | **4,723.1** | **4,355.6** | 4,332.6 |
| **Thermal Facilities:** | | | | | | |
| Windsor Locks | **N/A[5]** | **46.1** | 31.8 | **N/A[5]** | **154.7** | 122.0 |
| Sanger | **N/A[5]** | **11.3** | 33.5 | **N/A[5]** | **146.4** | 86.0 |
| | | **57.4** | 65.3 | | **301.1** | 208.0 |
| **Total Performance** | | **1,259.1** | 1,338.3 | | **4,656.7** | 4,540.6 |

1 APUC owns a 75% equity interest in the Red Lily Wind Facility but accounts for the facility using the equity method. The production figures represent full energy produced by the facility.

2 APUC owns a 50% equity interest in the Amherst Wind Facility. The Amherst Wind Facility achieved COD on June 15, 2018 in accordance with the terms of the PPA, however, the facility was partially operational prior to that date. The production data includes all energy produced during the year.

3 The Deerfield Wind Facility achieved COD on February 21, 2017 and was treated as an equity investment until March 14, 2017 at which time the Company acquired the remaining 50% ownership in the facility. The production noted above represents all production from the date of COD.

4 The Great Bay Solar Facility achieved COD on March 29, 2018 in accordance with the terms of the PPA, however, the facility was partially operational prior to that date. The production data includes all energy produced during the year.

5 Natural gas fired co-generation facility.

## 2018 Fourth Quarter Liberty Power Group Performance

For the three months ended December 31, 2018, the Liberty Power Group generated 1,259.1 GW-hrs of electricity as compared to 1,338.3 GW-hrs during the same period of 2017.

For the three months ended December 31, 2018, the hydro facilities generated 147.5 GW-hrs of electricity as compared to 143.5 GW-hrs produced in the same period in 2017, an increase of 2.8%. Electricity generated represented 99.0% of long-term average resources ("LTAR") as compared to 92.8% during the same period in 2017. During the quarter, all regions except the Maritime Region were above their respective LTAR.

For the three months ended December 31, 2018, the wind facilities produced 1,016.5 GW-hrs of electricity as compared to 1,114.7 GW-hrs produced in the same period in 2017, a decrease of 8.8%. During the three months ended December 31, 2018, the wind facilities (excluding the Amherst Wind Facility) generated electricity equal to 88.8% of LTAR as compared to 103.3% during the same period in 2017 primarily due to lower wind resource.

For the three months ended December 31, 2018, the solar facilities generated 37.7 GW-hrs of electricity as compared to 14.8 GW-hrs of electricity in the same period in 2017, an increase of 154.7%. The increase in production is primarily due to the addition of the Great Bay Solar Facility which achieved full COD on March 29, 2018. The solar facilities (excluding the Great Bay Solar Facility) production was 25.7% below its LTAR as compared to 2.6% below in the same period in 2017 primarily due to lower irradiance.

For the three months ended December 31, 2018, the thermal facilities generated 57.4 GW-hrs of electricity as compared to 65.3 GW-hrs of electricity during the same period in 2017. During the same period, the Windsor Locks Thermal Facility generated 145.7 billion lbs of steam as compared to 136.9 billion lbs of steam during the same period in 2017.

## 2018 **Annual Liberty Power Group** Performance

For the twelve months ended December 31, 2018, the Liberty Power Group generated 4,656.7 GW-hrs of electricity as compared to 4,540.6 GW-hrs during the same period of 2017.

For the twelve months ended December 31, 2018, the hydro facilities generated 537.5 GW-hrs of electricity as compared to 589.4 GW-hrs produced in the same period in 2017, a decrease of 8.8%. Electricity generated represented 88.6% of LTAR as compared to 94.7% during the same period in 2017. The decrease is primarily due to reduced hydrology in the Maritime and Ontario Regions.

For the twelve months ended December 31, 2018, the wind facilities produced 3,623.0 GW-hrs of electricity as compared to 3,658.3 GW-hrs produced in the same period in 2017, a decrease of 1.0%. During the twelve months ended December 31, 2018, the wind facilities generated electricity equal to 92.7% of LTAR as compared to 98.7% during the same period in 2017. The decrease in production was partially offset by higher production at the St. Damase Wind Facility as well as the incremental electricity generated at the Deerfield and Amherst Wind Facilities which achieved COD on February 21, 2017 and June 15, 2018, respectively.

For the twelve months ended December 31, 2018, the solar facilities generated 195.1 GW-hrs of electricity as compared to 84.9 GW-hrs of electricity produced in the same period in 2017, an increase of 129.8%. The increase in production is primarily due to the addition of the Great Bay Solar Facility which achieved full COD on March 29, 2018. The solar facilities (excluding the Great Bay Solar Facility) production was 8.1% below its LTAR as compared to 7.6% below in the same period in 2017.

For the twelve months ended December 31, 2018, the thermal facilities generated 301.1 GW-hrs of electricity as compared to 208.0 GW-hrs of electricity during the same period in 2017. During the same period, the Windsor Locks Thermal Facility generated 566.9 billion lbs of steam as compared to 559.1 billion lbs of steam during the same period in 2017.

## 2018 Liberty Power Group Operating Results

| (all dollar amounts in $ millions) | Three Months Ended December 31 2018 | 2017 | Twelve Months Ended December 31 2018 | 2017 |
|---|---|---|---|---|
| Revenue[1] | | | | |
| Hydro | **$ 11.7** | $ 11.0 | **$ 42.6** | $ 44.7 |
| Wind | **37.7** | 42.5 | **133.5** | 132.1 |
| Solar | **2.8** | 1.6 | **17.2** | 10.8 |
| Thermal | **10.2** | 8.8 | **42.1** | 30.0 |
| **Total Revenue** | **$ 62.4** | $ 63.9 | **$ 235.4** | $ 217.6 |
| Less: | | | | |
| Cost of Sales - Energy[2] | **(1.4)** | (1.5) | **(5.5)** | (5.1) |
| Cost of Sales - Thermal | **(5.1)** | (4.6) | **(21.7)** | (14.5) |
| Realized gain/(loss) on hedges[3] | **0.1** | — | **0.1** | (0.7) |
| **Net Energy Sales[8]** | **$ 56.0** | $ 57.8 | **$ 208.3** | $ 197.3 |
| Renewable Energy Credits ("REC")[4] | **2.7** | 4.3 | **11.0** | 13.2 |
| Other Revenue | **0.4** | 0.1 | **0.9** | 0.4 |
| **Total Net Revenue** | **$ 59.1** | $ 62.2 | **$ 220.2** | $ 210.9 |
| Expenses & Other Income | | | | |
| Operating expenses | **(13.2)** | (17.3) | **(71.0)** | (66.9) |
| Interest, dividend, equity and other income[5] | **18.3** | 0.9 | **45.7** | 2.9 |
| HLBV income[6] | **14.5** | 9.9 | **108.7** | 45.9 |
| **Divisional Operating Profit[7,8]** | **$ 78.7** | $ 55.7 | **$ 303.6** | $ 192.8 |

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

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

[3] See *Note 23(b)(iv)* in the annual audited consolidated financial statements.

[4] Qualifying renewable energy projects receive 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.

[5] Includes dividends received from Atlantica of which APUC owns approximately 41.5% of the common shares (see *Note 8* in the annual audited consolidated financial statements).

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

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

[8] See *Non-GAAP Financial Measures*.

## 2018 Fourth Quarter Operating Results

For the three months ended December 31, 2018, the Liberty Power Group's facilities generated $78.7 million of operating profit as compared to $55.7 million during the same period in 2017, which represents an increase of $23.0 million or 41.3%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

| (all dollar amounts in $ millions) | Three Months Ended December 31 |
|---|---|
| **Prior Period Operating Profit** | **$ 55.7** |
| **Existing Facilities** | |
| Hydro: Increase is primarily due to higher production and favourable rates in the Western Region, partially offset by unfavourable rates in the Maritime Region. | 0.9 |
| Wind Canada: Decrease is primarily due to lower production. | (2.5) |
| Wind U.S.: Decrease is primarily due to lower production, partially offset by higher HLBV income at the Deerfield Wind Facility. | (1.7) |
| Solar Canada: Decrease is primarily due to lower production. | (0.1) |
| Solar U.S.: Decrease is primarily due to a change in HLBV income assumptions as a result of U.S. Tax Reform. | (1.1) |
| Thermal: Increase is primarily due to higher overall production as well as an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018, partially offset by an increase in fuel costs. | 0.3 |
| Other: Increase is primarily due higher dividend and equity income. | 4.8 |
| | **0.6** |
| **New Facilities and Investments** | |
| Solar U.S.: Great Bay Solar reached full COD in March 2018. | 4.7 |
| Wind Canada: Amherst Island Wind Facility interest and equity income received as it achieved COD in June 2018. | 2.7 |
| Atlantica & AAGES: Dividends from Atlantica, net of AAGES equity loss. | 15.6 |
| | **23.0** |
| **Foreign Exchange** | **(0.6)** |
| **Current Period Divisional Operating Profit[1]** | **$ 78.7** |

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

## 2018 Annual Operating Results

For the twelve months ended December 31, 2018, the Liberty Power Group's facilities generated $303.6 million of operating profit as compared to $192.8 million during the same period in 2017, which represents an increase of $110.8 million or 57.5%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

| (all dollar amounts in $ millions) | | Twelve Months Ended December 31 |
|---|---|---|
| **Prior Period Operating Profit** | **$** | **192.8** |
| **Existing Facilities** | | |
| Hydro: Decrease is primarily due to lower production and the recognition of a bonus payment from Hydro Quebec in the prior year, partially offset by favourable rates in the Western Region. | | (2.5) |
| Wind Canada: Decrease is primarily due to lower overall production | | (2.6) |
| Wind U.S.: Increase is primarily due to HLBV income acceleration resulting from U.S. Tax Reform [1], partially offset by lower production. | | 41.6 |
| Solar Canada: Increase is primarily due to higher production. | | 0.1 |
| Thermal: Increase is primarily due to higher overall production as well as an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018, partially offset by an increase in fuel costs. | | 3.5 |
| Other: Increase is primarily due higher dividend and equity income. | | 4.9 |
| | | **45.0** |
| **New Facilities and Investments** | | |
| Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017. | | 13.5 |
| Solar U.S.: Great Bay Solar achieved full COD in March 2018. | | 10.7 |
| Wind Canada: Amherst Island Wind Facility interest and equity income received as it achieved COD in June 2018. | | 4.3 |
| Atlantica & AAGES: Dividends from Atlantica, net of AAGES equity loss. | | 37.4 |
| | | **65.9** |
| **Foreign Exchange** | | **(0.1)** |
| **Current Period Divisional Operating Profit[2]** | **$** | **303.6** |

[1] As a result of U.S. Tax Reform, the differential membership interests associated with the Company's renewable energy projects in the U.S. that utilized tax equity were remeasured. This remeasurement resulted in an acceleration of income associated with HLBV in the amount of $55.9 million for the existing Wind U.S. and Solar U.S. facilities at the Liberty Power Group. Over the remaining life of existing tax equity structures of APUC, U.S. Tax Reform on balance has not materially affected, either positively or negatively, the economic benefits of the underlying tax equity structures in total.

[2] See *Non-GAAP Financial Measures*.

## APUC: CORPORATE AND OTHER EXPENSES

| (all dollar amounts in $ millions) | Three Months Ended December 31 2018 | 2017 | Twelve Months Ended December 31 2018 | 2017 |
|---|---|---|---|---|
| Corporate and other expenses: | | | | |
| Administrative expenses | **$ 15.0** | $ 14.7 | **$ 52.7** | $ 49.6 |
| Loss (gain) on foreign exchange | **0.7** | 1.3 | **(0.1)** | 0.3 |
| Interest expense on convertible debentures and costs related to acquisition financing | **—** | — | **—** | 13.4 |
| Interest expense | **40.3** | 33.4 | **152.1** | 142.4 |
| Depreciation and amortization | **63.8** | 69.2 | **260.8** | 251.3 |
| Change in value of investment carried at fair value | **46.0** | — | **138.0** | — |
| Interest, dividend, equity, and other loss (income) [1] | **(0.4)** | (0.5) | **(1.8)** | (2.2) |
| Pension and post-employment non-service costs [2] | **1.4** | 2.5 | **3.9** | 9.0 |
| Other losses | **2.3** | 3.7 | **2.7** | 0.7 |
| Acquisition-related costs, net | **(8.9)** | 1.0 | **0.7** | 47.7 |
| Loss (gain) on derivative financial instruments | **(0.3)** | (3.1) | **0.6** | (1.9) |
| Income tax expense | **2.8** | 29.7 | **53.4** | 73.4 |

[1] Excludes income directly pertaining to the Liberty Power and Liberty Utilities Groups (disclosed in the relevant sections).

[2] Pension amounts previously noted as part of operating expenses. See *Note 10* in the annual audited consolidated financial statements for further details.

### 2018 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2018, administrative expenses totaled $15.0 million as compared to $14.7 million in the same period in 2017.

For the three months ended December 31, 2018, interest expense totaled $40.3 million as compared to $33.4 million in the same period in 2017. The increase is primarily due to drawings under the Corporate Term Facility and issuance of Fixed-to-Floating Subordinated Notes in October 2018, partially offset by debt maturities.

For the three months ended December 31, 2018, depreciation expense totaled $63.8 million as compared to $69.2 million in the same period in 2017. The decrease is primarily due to a one-time adjustment due to regulatory proceedings.

For the three months ended December 31, 2018, change in investment carried at fair value totaled $46.0 million as compared to $nil in 2017. The 2018 change in fair value reflects an unrealized loss related to the investment in Atlantica (see *Note 8* in the annual audited consolidated financial statements).

For the three months ended December 31, 2018, pension and post-employment non-service costs totaled $1.4 million as compared to $2.5 million in 2017.

For the three months ended December 31, 2018, other losses were $2.3 million as compared to $3.7 million in the same period in 2017. The loss in 2018 mainly relates to the write down of notes receivables and costs from condemnation proceedings. The loss in 2017 was primarily attributable to an increase in regulatory liabilities in the LPSCo Water System resulting from ongoing regulatory proceedings.

For the three months ended December 31, 2018, acquisition related cost recovery totaled $8.9 million as compared to an expense of $1.0 million in 2017. The decrease is primarily due to a settlement related to the Shady Oaks Wind Facility acquisition.

For the three months ended December 31, 2018, gains on derivative financial instruments totaled $0.3 million as compared to $3.1 million in the same period in 2017. The gains in 2017 were primarily driven by mark-to-market gains on commodity derivatives.

For the three months ended December 31, 2018, an income tax expense of $2.8 million was recorded as compared to an income tax expense of $29.7 million during the same period in 2017. The decrease in income tax expense is primarily due to U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

## 2018 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2018, administrative expenses totaled $52.7 million as compared to $49.6 million in the same period in 2017. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth.

For the twelve months ended December 31, 2018, interest expense on convertible debentures and bridge financing totaled $nil as compared to $13.4 million in the same period in 2017. The 2017 expense related to non-recurring financing costs related to the acquisition of Empire, as well as interest expense on convertible debentures before conversion to common shares in the first quarter of 2017.

For the twelve months ended December 31, 2018, interest expense totaled $152.1 million as compared to $142.4 million in the same period in 2017. The increase is primarily due to drawings under the Corporate Term Facility and issuance of Fixed-to-Floating Subordinated Notes in October 2018, partially offset by debt maturities.

For the twelve months ended December 31, 2018, depreciation expense totaled $260.8 million as compared to $251.3 million in the same period in 2017. The increase is primarily due to an increase in property, plant and equipment.

For the twelve months ended December 31, 2018, change in investment carried at fair value totaled $138.0 million as compared to $nil in the same period in 2017. The 2018 change in fair value reflects an unrealized loss related to the investment in Atlantica (see *Note 8* in the annual audited consolidated financial statements).

For the twelve months ended December 31, 2018, pension and post-employment non-service costs totaled $3.9 million as compared to $9.0 million in the same period in 2017. The decrease is primarily due to a higher return on plan assets in 2018.

For the twelve months ended December 31, 2018, other losses were $2.7 million as compared to a loss of $0.7 million in the same period in 2017. The loss in 2018 mainly relates to the write down of notes receivables and costs from condemnation proceedings. The prior period loss is primarily related to the write-off of rate review expenses for several water utilities, partially offset by the disposition of the Mountain Water utility.

For the twelve months ended December 31, 2018, acquisition-related costs totaled $0.7 million as compared to $47.7 million in the same period in 2017. The costs in 2018 primarily related to the investment in Atlantica, partially offset by a settlement related to the Shady Oaks Wind Facility acquisition. The costs in 2017 primarily related to the acquisition of Empire.

For the twelve months ended December 31, 2018, the loss on derivative financial instruments totaled $0.6 million as compared to a gain of $1.9 million in the same period in 2017. The gain in 2017 was primarily due to mark-to-market gains on commodity derivatives. The loss in 2018 is primarily due to the ineffective portion related to the extension of the Liberty Power Group's interest rate hedge on expected debt financing.

An income tax expense of $53.4 million was recorded in the twelve months ended December 31, 2018 as compared to an income tax expense of $73.4 million during the same period in 2017. The decrease in income tax expense is primarily due to U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

## U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act ("U.S. Tax Reform" or the "Act"), was signed into law which among other things, reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. As a result, in the fourth quarter of 2017, the Company was required to revalue its U.S. deferred income tax assets and liabilities based on the new tax rate. This remeasurement resulted in a non-cash accounting charge of $17.1 million which was recorded in the Company's 2017 consolidated statement of operations.

In 2018, the Company completed its remeasurement of deferred income tax assets and liabilities as permitted under the measurement period outlined under SEC Staff Accounting Bulletin 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act ("SAB 118"). The final adjustments related to the implementation of U.S. Tax Reform resulted in a non-cash accounting benefit of $18.4 million which was recorded in the Company's 2018 consolidated statement of operations.

# NON-GAAP FINANCIAL MEASURES

## Reconciliation of Adjusted EBITDA to Net Earnings

The following table is derived from and should be read in conjunction with the 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 U.S. GAAP consolidated net earnings.

| (all dollar amounts in $ millions) | Three Months Ended December 31 | | Twelve Months Ended December 31 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Net earnings attributable to shareholders | **$ 44.0** | $ 47.2 | **$ 185.0** | $ 149.5 |
| Add (deduct): | | | | |
| Net earnings attributable to the non-controlling interest, exclusive of HLBV | **3.4** | 0.6 | **4.8** | 2.4 |
| Income tax expense | **2.8** | 29.7 | **53.4** | 73.4 |
| Interest expense on convertible debentures and costs related to acquisition financing | **—** | — | **—** | 13.4 |
| Interest expense on long-term debt and others | **40.3** | 33.3 | **152.1** | 142.4 |
| Other losses | **2.3** | 3.8 | **2.7** | 0.7 |
| Acquisition-related costs | **(8.9)** | 1.0 | **0.7** | 47.7 |
| Pension and post-employment non-service costs [1] | **1.4** | 2.5 | **3.9** | 9.0 |
| Change in value of investment in Atlantica carried at fair value | **46.0** | — | **138.0** | — |
| Costs related to tax equity financing | **1.3** | 0.4 | **1.3** | 1.8 |
| Loss (gain) on derivative financial instruments | **(0.3)** | (3.1) | **0.6** | (1.9) |
| Realized (loss) gain on energy derivative contracts | **0.1** | — | **0.1** | (0.6) |
| Loss (gain) on foreign exchange | **0.7** | 1.2 | **(0.1)** | 0.3 |
| Depreciation and amortization | **63.8** | 69.2 | **260.8** | 251.3 |
| **Adjusted EBITDA** | **$ 196.9** | $ 185.8 | **$ 803.3** | $ 689.4 |

[1] As a result of adoption of ASU 2017-07 certain components of net benefit pension costs are considered non-service costs and are now classified outside of operating income (see *Note 2(a)* in the annual audited consolidated financial statements).

HLBV represents the value of net tax attributes earned during the period primarily from electricity generated by certain U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2018 amounted to $13.8 million and $110.7 million as compared to $11.3 million and $52.1 million during the same period in 2017. In the first quarter of 2018 a one-time acceleration of HLBV income in the amount of $55.9 million was recorded as a result of U.S. Tax Reform.

## Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the 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 U.S. GAAP.

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

| (all dollar amounts in $ millions) | Three Months Ended December 31 2018 | 2017 | Twelve Months Ended December 31 2018 | 2017 |
|---|---|---|---|---|
| Net earnings attributable to shareholders | **$ 44.0** | $ 47.2 | **$ 185.0** | $ 149.5 |
| Add (deduct): | | | | |
| Loss (gain) on derivative financial instruments | **(0.3)** | (3.1) | **0.6** | (1.9) |
| Realized (loss) gain on energy derivative contracts | **0.1** | — | **0.1** | (0.6) |
| Loss (gain) on long-lived assets, net | **1.9** | 1.2 | **0.8** | (1.8) |
| Loss (gain) on foreign exchange | **0.7** | 1.2 | **(0.1)** | 0.3 |
| Interest expense on convertible debentures and costs related to acquisition financing | **—** | — | **—** | 13.4 |
| Acquisition-related costs | **(8.9)** | 1.0 | **0.7** | 47.7 |
| Change in value of investment in Atlantica carried at fair value | **46.0** | — | **138.0** | — |
| Costs related to tax equity financing | **1.3** | 0.4 | **1.3** | 1.8 |
| Other adjustments | **—** | 2.5 | **—** | 2.5 |
| U.S. Tax Reform and related deferred tax adjustments [1] | **(18.4)** | 17.1 | **(18.4)** | 17.1 |
| Adjustment for taxes related to above | **4.1** | (0.5) | **4.2** | (3.0) |
| **Adjusted Net Earnings** | **$ 70.5** | $ 67.0 | **$ 312.2** | $ 225.0 |
| **Adjusted Net Earnings per share [2]** | **$ 0.14** | $ 0.16 | **$ 0.66** | $ 0.57 |

[1] Represents the non-cash accounting charge related to the revaluation of U.S. deferred income tax assets and liabilities as a result of implementation of the effects of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

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

For the three months ended December 31, 2018, Adjusted Net Earnings totaled $70.5 million as compared to Adjusted Net Earnings of $67.0 million for the same period in 2017, an increase of $3.5 million.

For the twelve months ended December 31, 2018, Adjusted Net Earnings totaled $312.2 million as compared to Adjusted Net Earnings of $225.0 million for the same period in 2017, an increase of $87.2 million.

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

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

| (all dollar amounts in $ millions) | Three Months Ended December 31 | | Twelve Months Ended December 31 | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Cash flows from operating activities | **$ 168.6** | $ 116.0 | **$ 530.4** | $ 326.6 |
| Add (deduct): | | | | |
| Changes in non-cash operating items | **(27.3)** | 9.1 | **8.1** | 87.7 |
| Production based cash contributions from non-controlling interests | **—** | — | **13.9** | 7.9 |
| Interest expense on convertible debentures and costs related to acquisition financing[1] | **—** | — | **—** | 7.2 |
| Acquisition-related costs | **(8.8)** | 0.9 | **0.7** | 47.7 |
| Reimbursement of operating expenses incurred on joint venture | **—** | — | **1.0** | — |
| **Adjusted Funds from Operations** | **$ 132.5** | $ 126.0 | **$ 554.1** | $ 477.1 |

1 Exclusive of deferred financing fees of $6.2 million.

For the three months ended December 31, 2018, Adjusted Funds from Operations totaled $132.5 million as compared to Adjusted Funds from Operations of $126.0 million for the same period in 2017, an increase of $6.5 million.

For the twelve months ended December 31, 2018, Adjusted Funds from Operations totaled $554.1 million as compared to Adjusted Funds from Operations of $477.1 million for the same period in 2017, an increase of $77.0 million.

# CORPORATE DEVELOPMENT ACTIVITIES

The Company's worldwide development activities for projects either owned directly by the Company or indirectly through AAGES entities are undertaken primarily by AAGES, a joint venture formed with Abengoa. AAGES and its affiliates work with a global reach to identify, develop, and construct new renewable power generating facilities, power transmission lines and water infrastructure assets. Once a project developed by AAGES has reached commercial operation, a determination will be made on whether it will be optimal for such project to be held by APUC, remain in AAGES, or be offered for sale to Atlantica or, in limited circumstances, another party.

The Company has an identified development pipeline of approximately $4.0 billion over the next 5 years consisting of potential investments in $1.4 billion in North American regulated renewable generation assets, $1.7 billion of North American unregulated renewable generation assets, $0.4 billion in regulated electric and gas transmission assets and $0.5 billion in international development projects.

The projects identified are at various stages of development, and have advanced to a stage where the resolutions to major project uncertainties such as regulatory approvals, land control, economic and other contractual issues are probable, but not certain, and it is expected that the project will meet management's risk adjusted return expectations.

## Projects Completed

**Great Bay Solar Project**

The Great Bay Solar Project is a 75 MW solar powered electric generating facility comprising four sites located in Somerset County in southern Maryland.

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

The project achieved commercial operation in two phases: 20 MW on December 30, 2017 and 55 MW on March 29, 2018.

**Amherst Island Wind Project**

The Amherst Island Wind Project is a 75 MW wind powered electric generating facility located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is composed of 26 Siemens 3.2 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold under a PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority.

During the year, the Amherst Project achieved COD, and received notice from the IESO confirming that the FIT term commenced June 15, 2018, and that the FIT contract remains in full force and effect.

During 2018, the Liberty Power Group's interest in the project was held in a joint venture with the EPC contractor; subsequent to year-end, the Liberty Power Group exercised its option to acquire, at a pre-agreed price, the balance of the joint venture interest not previously owned. The acquisition is subject to regulatory approval, which is expected to be obtained in 2019.

## Projects in Construction

**Turquoise Solar Project**

The Turquoise Solar Project is a 10 MW solar powered electric generating development project located in Washoe County in Nevada.

The project is expected to generate 28 GW-hrs of energy per year which will be consumed by the Calpeco Electric System customers.

The Liberty Utilities Group believes that the project will qualify for U.S. federal investment tax credits. Investment in the project by the Calpeco Electric System, net of the third party tax equity investment sought to efficiently use the tax attributes from the project, has been approved by the California Public Utility Commission for inclusion in the rate base of the utility. The cost of energy from the project is forecast to result in savings to the energy costs incurred by the Calpeco Electric System customers.

The project reached mechanical completion in the fourth quarter of 2018, and commissioning is due to be completed in the first quarter of 2019.

## North American Development Activities

**Mid-West Wind Development Project**

In 2017, the Liberty Utilities Group presented a plan to the MPSC for an investment in up to 600 MW of strategically located wind energy generation which is forecast to reduce energy costs for its customers. On July 11, 2018, an order was received from the MPSC supporting various requests related to the proposed investment plan.

Effective October 11, 2018, Empire entered into purchase agreements with a developer for two wind development projects, North Fork Ridge and Kings Point, and effective November 16, 2018, entered into a third purchase agreement with another developer for Neosho Ridge, with total combined capacity of 600 MW. The agreements contain development milestones and termination provisions that primarily apply prior to the commencement of construction. Agreements have also been executed for the design and construction of the projects. These projects are located in Kansas and Missouri, within the Empire District Electric System service territory, and are expected to begin construction in the second half of 2019, subject to the receipt of certain regulatory approvals. The estimated construction cycle for the projects is 12 to 18 months.

The proposed new wind generating capacity is forecast to generate approximately 2,400 GW-hrs of energy per year for consumption by the Empire Electric System customers.

The development and construction costs of the three projects comprising the 600 MW plan, net of third party tax equity investment sought to efficiently use the tax attributes from the projects, are expected to be included in the rate base of the Empire Electric System. The cost of energy from the projects is forecast to result in savings to the energy costs incurred by the Empire Electric System customers.

**Granite Bridge Project**

The Liberty Utilities Group is developing the Granite Bridge Project, which has been conceived to help relieve supply constraints impacting the Liberty Utilities Group's natural gas distribution customers in order to reduce customer gas energy costs and support continued economic growth. The project comprises a proposed 26 mile natural gas pipeline, connecting the Portland Natural Gas Transmission System, the Maritimes & Northeast Pipeline (Joint Facilities) and the Tennessee Gas Concord Lateral, which provides service to the Liberty Utilities Groups' New Hampshire distribution system. The pipeline will be constructed in a designated energy infrastructure corridor along Route 101, and will be completely within the New Hampshire Department of Transportation ("NHDOT") right of way in New Hampshire. In addition, the project includes a proposed 2 bcf full containment storage tank and liquefaction and vaporization equipment, all of which will be located in an abandoned quarry to minimize visual impact to the host community of Epping, New Hampshire.

The Liberty Utilities Group filed for approval of its plan to construct the project with the NHPUC in December 2017, and a decision is expected in 2019.

The Liberty Utilities Group has commenced environmental, geotechnical and survey work on the project, and has received preliminary acceptance from the NHDOT on its proposed pipeline route. The Manchester, Hudson, Nashua, and Concord Chambers of Commerce have publicly endorsed the project, together with the New Hampshire Building Trades. In addition, a bipartisan group of 22 State senators has publicly endorsed the project.

The development and construction costs of the project are expected to be included in the rate base of the EnergyNorth Natural Gas System.

Final investment decision will be made following receipt of NHPUC and New Hampshire Site Evaluation Committee approvals.

**Sugar Creek Wind Project**

The Sugar Creek Wind Project is a 202 MW wind power electric development project located in Logan County, Illinois. Development of the project is underway. A long-term contract is in place with the Illinois Power Agency to provide renewable energy certificates from the project to utilities in the state. Energy from the project will be sold pursuant to a long-term financial hedge, which was executed in the fourth quarter of 2018 with a creditworthy counterparty. An initial agreement has been entered into to secure construction services for the project, with a definitive agreement expected during the first quarter of 2019. Initial payment has been made for project turbines for an anticipated delivery to site in the second quarter of 2020, and a turbine supply agreement for the project is expected to be signed in the first quarter of 2019. COD for the project is expected in the fourth quarter of 2020.

**Blue Hill Wind Project**

The Blue Hill Wind Project is a 177 MW wind powered electric generating development project located in the rural municipalities of Lawtonia and Morse in southwest Saskatchewan. The project is expected to generate approximately 800.0 GW-hrs of energy per year, with all energy sold to SaskPower pursuant to a 25 year PPA.

Ministerial approval to proceed with the development of the project was received from the Saskatchewan Ministry of Environment. The project has also received development permits from the municipalities of Lawtonia and Morse.

Based on the recently completed system impact study for the project, the expected time frame for design and construction is estimated to be between 24 and 36 months. SaskPower has commenced the Facilities Study phase of the interconnection procedures required to connect the Blue Hill Wind Project to SaskPower's transmission system. A geotechnical evaluation of the project site including existing infrastructure and municipal roads has been completed. The current project execution plan estimates the COD date for the project to be late 2021 or early 2022.

**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, near Quebec City. The Liberty Power Group holds a 50% interest in the project through a partnership created with the Val-Éo Wind Cooperative (a community based landowner consortium).

The project will be developed in two phases. Phase I of the project is expected to be completed in 2019 and is expected to have a total capacity of 24 MW, with all energy from Phase I of the project to be sold to Hydro-Québec Distribution pursuant to a 20-year PPA. Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements. All land agreements, construction permits and authorizations have been obtained for Phase I, except for final approval from Transport Canada and an agricultural land use permit expected in the first quarter of 2019.

During the second quarter of 2018, the Liberty Power Group executed an interconnection agreement with Hydro-Québec TransÉnergie. Additionally, the Liberty Power Group executed a revised turbine supply agreement which resulted in approximately C$10 million in cost savings over the initial Phase I project cost estimates. On September 14, 2018, a service and maintenance agreement was executed with the turbine equipment supplier.

**Walker Ridge Wind Project**

The Walker Ridge Wind Project is a 144 MW wind power electric generating facility located in the counties of Lake and Colusa in northern California. The facility will be located on U.S. Bureau of Land Management land. A Large Generator Interconnection Agreement with CAISO and PG&E was executed in December 2018. Work is ongoing with respect to site design, environmental permitting and EPC engagement. Energy from the project is expected to be sold pursuant to a long term financial hedge. The expected COD date for the project is late 2020 or 2021.

**Broad Mountain Wind Project**

The Broad Mountain Wind Project is a 200 MW wind power electric generating facility located in Carbon County, Pennsylvania. Development of the project is planned to be completed in two phases. The first phase ("Phase I") representing installed capacity of 80 MW is targeted for completion, pending regulatory approvals, in 2020. The balance of the 120 MW of proposed capacity is targeted for completion in 2022. The project has secured the majority of land leases required, and environmental and interconnection studies are underway including geotechnical investigations, FAA permits and zoning applications for Phase I. Energy from Phase I of the project is expected to be sold pursuant to a long term financial hedge, and/or PPAs to local end users.

**Shady Oaks II Wind Project**

The Shady Oaks II Wind Project is a 120 MW expansion of the Liberty Power Group's operational Shady Oaks Wind Facility, located in Lee County, Illinois. The project will be located on land adjacent to the existing facility, and, subject to interconnection studies that are currently in progress, will connect to the same point of interconnection. Work on environmental permitting and site design are ongoing. Energy from the expansion project is expected to be sold pursuant to a long term financial hedge. The expected COD date for the project is late 2020 or 2021.

**Sandy Ridge II Wind Project**

The Sandy Ridge II Wind Project is a 60 to 100 MW expansion of the Liberty Power Group's operational Sandy Ridge Wind Facility, located in Centre County, Pennsylvania. The project will be located on land adjacent to the existing facility, and, subject to interconnection studies that are currently in progress, will connect to the same point of interconnection. Work on environmental permitting and site design is ongoing. Energy from the expansion project is expected to be sold pursuant to a long term financial hedge. The expected COD date for the project is late 2020 or early 2021.

**Great Bay II Solar Project**

The Great Bay II Solar Project is an approximately 45 MW expansion of the Liberty Power Group's operational Great Bay Solar Facility, located in Somerset County in southern Maryland. The project will be located on land nearby the existing facility, and will connect to the same point of interconnection. Work on environmental permitting and site design is ongoing. Energy from the expansion project is expected to be sold pursuant to a long-term financial hedge. The expected COD date for the project is late 2019 or early 2020.

**Wataynikaneyap Power Transmission Project**

The Liberty Utilities Group acquired a 9.8% ownership interest in an electricity transmission project located in Northwestern Ontario (the "Wataynikaneyap Power Transmission Project") from Fortis Inc. that is expected to connect 17 remote First Nation communities to the Ontario provincial electricity grid through the construction of approximately 1,800 km of transmission lines. Ownership of the Wataynikaneyap Power Transmission Project is divided as follows: 9.8% held by the Liberty Utilities Group, 39.2% held by Fortis Inc. and 51% held equally among 24 First Nation partners.

The initial phase of the Wataynikaneyap Power Transmission Project connecting Pikangikum First Nation to Ontario's power grid was completed in late 2018. The next two phases are subject to receipt of all necessary regulatory approvals, including leave-to-construct approval from the Ontario Energy Board, which is expected in the first half of 2019. In addition to providing participating First Nations communities ownership in the transmission line, the Wataynikaneyap Power Transmission Project is expected to result in socio-economic benefits for surrounding communities, reduce environmental risk and lessen greenhouse gas emissions associated with diesel-fired generation currently used in the area.

## International Development Activities

As a component of the acquisition of its interest in Atlantica, Algonquin secured an opportunity for AAGES to evaluate participation in a number of development opportunities which had been previously advanced by Abengoa. Since its formation in the first quarter of 2018, the AAGES development team has been actively evaluating its interest in international projects, including the following project:

**ATN3 Electric Transmission Project**

The ATN3 electric transmission project is an electric transmission development project located in southeast Peru consisting of a new 220 kV power transmission line approximately 320 km in length, a new 138 kV power transmission line approximately 7.2 km in length, two new substations and the expansion of three existing substations. The ATN3 Project will be operated under a concession agreement with the government of Peru, with an operating period of 30 years from the commencement of commercial operation and which grants to ATN3 an annual fixed tariff denominated in U.S. dollars and indexed to the U.S. consumer price index. Ownership of the project will be transferred to the government of Peru at the end of the 30 year concession term.

On November 8, 2018, AAGES entered into a definitive agreement with Abengoa Perú S.A. and Abengoa Greenfield Perú S.A. to acquire the entity that owns the project. Closing of the transaction remains subject to certain conditions, including receipt of certain approvals from the government of Peru.

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

| (all dollar amounts in $ millions) | Three Months Ended December 31 2018 | 2017 | Twelve Months Ended December 31 2018 | 2017 |
|---|---|---|---|---|
| **Liberty Utilities Group:** | | | | |
| Rate Base Maintenance | **$ 41.5** | $ 45.9 | **$ 177.7** | $ 170.9 |
| Rate Base Acquisition | **—** | — | **—** | 2,058.2 |
| Rate Base Growth | **76.0** | 70.6 | **173.9** | 272.7 |
| | **$ 117.5** | $ 116.5 | **$ 351.6** | $ 2,501.8 |
| **Liberty Power Group:** | | | | |
| Maintenance | **$ 12.6** | $ 3.1 | **$ 27.4** | $ 13.9 |
| Investment in Capital Projects [1] | **(18.0)** | 13.4 | **71.6** | 469.9 |
| International Investments [2] | **345.0** | — | **957.6** | — |
| | **$ 339.6** | $ 16.5 | **$ 1,056.6** | $ 483.8 |
| **Total Capital Expenditures** | **$ 457.1** | $ 133.0 | **$ 1,408.2** | $ 2,985.6 |

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

[2] Investments in Atlantica are reflected at historical investment cost and not fair value.

### 2018 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2018, the Liberty Utilities Group invested $117.5 million in capital expenditures as compared to $116.5 million during the same period in 2017. The Liberty Utilities Group's investment was primarily related to the construction of transmission and distribution main replacements, work on new and existing substation assets, and initiatives relating to the safety and reliability at the electric and gas systems.

During the three months ended December 31, 2018, the Liberty Power Group incurred capital expenditures of $339.6 million as compared to $16.5 million during the same period in 2017. The Liberty Power Group's investment was primarily related to the acquisition of an additional 16.5% interest in Atlantica, development costs for the Sugar Creek Wind Project, and ongoing maintenance capital at existing operating sites, partially offset by a repayment of a loan provided to the Amherst Island Wind Project.

### 2018 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2018, the Liberty Utilities Group invested $351.6 million in capital expenditures as compared to $2.5 billion during the same period in 2017. Excluding the acquisition of Empire, the Liberty Utilities Group incurred capital expenditures of $443.6 million in 2017. The Liberty Utilities Group's investment was primarily related to the construction of transmission and distribution main replacements, the completion and start of work on new and existing substation assets, and initiatives relating to the safety and reliability at the electric and gas systems. Capital expenditures in the same period last year (excluding the acquisition of Empire) included the completion of the Luning Solar Facility and further development of Phase I of the North Lake Tahoe transmission project to upgrade the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

During the twelve months ended December 31, 2018, the Liberty Power Group incurred capital expenditures of $1,056.6 million as compared to $483.8 million during the same period in 2017. Excluding the 41.5% investment in Atlantica, the Liberty Power Group's investment was $99.0 million in 2018. The Liberty Power Group's investments primarily related to completion of the Great Bay Solar and Amherst Island Wind Facilities, early stages of environmental permitting for the Blue Hill Wind Project, the finalization of material construction contracts on the Val Eo Wind Project and ongoing maintenance capital at existing operating sites.

## 2019 Capital Investments

In 2019, the Company plans to spend between $1.4 billion and $1.6 billion on capital investment opportunities. Actual expenditures during the course of 2019 may vary due to timing of various project investments and the realized Canadian to U.S. dollar exchange rate.

Expected 2019 capital investment ranges are as follows:

**(all dollar amounts in $ millions)**

| | | | | | |
|---|---|---|---|---|---|
| **Liberty Utilities Group:** | | | | | |
| Rate Base Maintenance | $ | 180.0 | - | $ | 200.0 |
| Rate Base Growth | | 280.0 | - | | 320.0 |
| Utility Acquisitions | | 350.0 | - | | 370.0 |
| Total Liberty Utilities Group: | $ | 810.0 | - | $ | 890.0 |
| | | | | | |
| **Liberty Power Group:** | | | | | |
| Maintenance | $ | 30.0 | - | $ | 40.0 |
| Investment in Capital Projects | | 340.0 | - | | 370.0 |
| International Investments | | 220.0 | - | | 300.0 |
| Total Liberty Power Group: | $ | 590.0 | - | $ | 710.0 |
| **Total 2019 Capital Investments** | **$** | **1,400.0** | **-** | **$** | **1,600.0** |

The Liberty Utilities Group intends to spend between $810.0 million - $890.0 million over the course of 2019 in an effort to expand our operations, improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Projects entail spending capital for structural improvements, specifically in relation to refurbishing substations, replacing poles and wires, drilling and equipping aquifers, main replacements, and reservoir pumping stations. Liberty expects to close the acquisitions of New Brunswick Gas, St. Lawrence Gas and the Turquoise Solar Project in 2019.

The Company expects to fund its 2019 capital plan through a combination of retained cash, tax equity funding, senior and subordinated debentures, bank revolving and term credit facilities, and common equity.

The Liberty Power Group intends to spend between $590.0 million - $710.0 million over the course of 2019 to develop or further invest in capital projects, primarily in relation to: (i) the purchase of the Amherst Island Wind Project from our Joint Venture Partner, (ii) development of the Sugar Creek Wind and Great Bay II Solar Projects, and (iii) additional international investments. The Liberty Power Group plans to spend $30.0 million - $40.0 million on various operational solar, thermal, and wind assets to maintain safety, regulatory, and operational efficiencies.

## LIQUIDITY AND CAPITAL RESERVES

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

### Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at December 31, 2018:

| | As at December 31, 2018 | | | | As at Dec 31, 2017 |
|---|---|---|---|---|---|
| (all dollar amounts in $ millions) | Corporate | Liberty Utilities | Liberty Power | Total | Total |
| Committed facilities | $ 121.0 | $ 500.0 | $ 700.0[1] | **$ 1,321.0** | $ 1,101.4 |
| Funds drawn on facilities/ Commercial paper issued | — | (103.0) | — | **(103.0)** | (54.3) |
| Letters of credit issued | (13.5) | (7.8) | (149.8) | **(171.1)** | (139.3) |
| Liquidity available under the facilities | **107.5** | **389.2** | **550.2** | **1,046.9** | 907.8 |
| Cash on hand | | | | **46.8** | 43.5 |
| **Total Liquidity and Capital Reserves** | **$ 107.5** | **$ 389.2** | **$ 550.2** | **$ 1,093.7** | $ 951.3 |

1 Includes a $200 million uncommitted stand alone letter of credit facility.

As at December 31, 2018, the Company's C$165.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $13.5 million of outstanding letters of credit. In November 2018, the facility's maturity was extended to November 19, 2019.

On December 21, 2017, the Company entered into a $600.0 million term credit facility with two Canadian banks ( "Corporate Term Credit Facility"). The proceeds of the Corporate Term Credit Facility provide the Company with additional liquidity for general corporate purposes and acquisitions. On March 7, 2018 the Company drew $600.0 million under this facility and during the second and fourth quarter the Company repaid $132.5 million and $280.7 million respectively on the facility. In December 2018, the facility's maturity was extended to June 21, 2019. The Company plans to refinance the Corporate Credit Facility and the Corporate Term Credit Facility with a new revolving credit facility in the first half of 2019.

On February 23, 2018, the Liberty Utilities Group increased commitments on its senior unsecured syndicated revolving credit facility (the "Liberty Credit Facility") to $500.0 million and extended the maturity to February 23, 2023. In conjunction with the increase to the Liberty Credit Facility, the $200.0 million revolving credit facility at Empire was canceled. The Liberty Credit Facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire. As at December 31, 2018 the Liberty Credit Facility had drawn $97.0 million, backstopped $6.0 million in commercial paper issuances, and had $7.8 million in outstanding letters of credit.

As at December 31, 2018, the Liberty Power Group's bank lines consisted of a $500.0 million senior unsecured syndicated revolving credit facility (the "Liberty Power Credit Facility") maturing on October 6, 2023 and a $200.0 million letter of credit facility ("Liberty Power LC Facility") maturing January 31, 2021. As at December 31, 2018, the Liberty Power Credit Facility was undrawn and a total of $149.8 million of letters of credit were issued under this facility and the standalone Liberty Power LC Facility.

### Long Term Debt

On June 1, 2018, the Company repaid, upon its maturity, a $90.0 million secured utility note.

On July 25, 2018, the Company repaid, upon its maturity, a C$135.0 million unsecured note.

Issuance of Subordinated Notes

On October 17, 2018, APUC issued $287.5 million of 6.875% fixed-to-floating subordinated notes. The issuance of the subordinated notes represented APUC's inaugural entry into the U.S. public debt markets. The subordinated notes are listed on the NYSE under the ticker symbol "AQNA".

The notes mature 60 years from issuance and are callable on or after year 5. For the initial 5 years, the notes carry a fixed interest rate of 6.875%. Subsequently, the interest rate will be set to equal the three-month London Interbank Offered Rate (LIBOR) plus a margin of 367.7 basis points from years 5 to 10, a margin of 392.7 basis points from years 10 to 25 and a margin of 467.7 basis points from years 25 to 60. The notes were initially assigned a rating of BB+/BB+ from S&P and Fitch. The notes were treated by both rating agencies as hybrid capital, receiving up to 50% equity credit for the balance outstanding. The notes contain a 102% of par call feature in the event of a rating methodology change by either agency that would reduce the amount of the equity credit.

APUC believes the use of subordinated notes structured as hybrid capital is a cost effective financing method that can be used to obtain balance sheet equity credit. APUC plans to continue to expand this portion of its capital structure as a means to diversify its financing sources.

Issuance of Green Bonds

Subsequent to year-end on January 29, 2019, the Liberty Power Group issued C$300.0 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures were sold at a price of $999.52 per $1000.00 principal amount. The debentures represent Liberty Power Group's inaugural "green bond" offering, and are closely aligned with the Company's commitment to advancing a sustainable energy and water future. Under its recently implemented Green Bond Framework, the proceeds of any "green bond" offering are to be used to finance and/or refinance investments in renewable power generation and clean energy technologies.

As at December 31, 2018, the weighted average tenor of APUC's total long term debt is approximately 17 years with an average interest rate of 4.8%.

## Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB from Standard & Poor's ("S&P"), a BBB rating from DBRS and a BBB issuer rating from Fitch.

LUCo, parent company for the Liberty Utilities Group, has a corporate credit rating of BBB from S&P and a BBB issuer rating from Fitch. Debt issued by Liberty Finance, a special purpose financing entity of LUCo, has a rating of BBB (high) from DBRS and BBB+ from Fitch. Empire has an issuer rating of BBB from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

APCo, the parent company for the Liberty Power Group, has a BBB issuer rating from S&P, a BBB issuer rating from DBRS and a BBB issuer rating from Fitch.

## Contractual Obligations

Information concerning contractual obligations as of December 31, 2018 is shown below:

| (all dollar amounts in $ millions) | Total | Due less than 1 year | Due 1 to 3 years | Due 4 to 5 years | Due after 5 years |
|---|---|---|---|---|---|
| Principal repayments on debt obligations[1] | **$ 3,321.8** | $ 334.9 | $ 420.8 | $ 825.6 | $ 1,740.5 |
| Convertible debentures | **0.5** | — | — | — | 0.5 |
| Advances in aid of construction | **63.7** | 1.2 | — | — | 62.5 |
| Interest on long-term debt obligations[2] | **1,576.9** | 156.8 | 269.9 | 221.5 | 928.7 |
| Purchase obligations | **325.3** | 325.3 | — | — | — |
| Environmental obligations | **59.2** | 4.2 | 30.1 | 2.9 | 22.0 |
| Derivative financial instruments: | | | | | |
| Cross currency swap | **93.2** | 5.3 | 46.0 | 34.4 | 7.5 |
| Interest rate swap | **8.5** | 8.5 | — | — | — |
| Energy derivative and commodity contracts | **1.2** | 0.6 | 0.5 | 0.1 | — |
| Purchased power | **282.6** | 46.5 | 22.0 | 22.9 | 191.2 |
| Gas delivery, service and supply agreements | **251.8** | 77.7 | 79.0 | 46.8 | 48.3 |
| Service agreements | **512.0** | 43.7 | 77.5 | 78.2 | 312.6 |
| Capital projects | **76.8** | 67.6 | 1.9 | 7.3 | — |
| Operating leases | **214.4** | 7.6 | 14.3 | 13.9 | 178.6 |
| Other obligations | **155.8** | 33.4 | — | — | 122.4 |
| **Total Obligations** | **$ 6,943.7** | **$ 1,113.3** | **$ 962.0** | **$ 1,253.6** | **$ 3,614.8** |

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

[2] The subordinated notes have a maturity in 2078, however management intent is to repay in 2023 upon exercising its redemption right.

## Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2018, APUC had 488,851,433 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 April 24, 2018, APUC closed the sale of approximately 37.5 million of its common shares to certain institutional investors at a price of C$11.85 per share, for gross proceeds of approximately C$444.4 million. The proceeds of the offering were used to pay down existing indebtedness and in part, to finance the purchase of the additional 16.5% interest in Atlantica.

On December 20, 2018, APUC closed the sale of approximately 12.5 million of its common shares to certain institutional investors at a price of C$13.76 per share, for gross proceeds of approximately C$172.5 million. The proceeds of the offering are anticipated to be used to partially finance APUC's recently announced acquisition of New Brunswick Gas, and for general corporate purposes.

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, 2018, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 5.162% annually for the five-year period ending on December 31, 2023;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of common shares of APUC. As at December 31, 2018, 123,522,018 common shares representing approximately 25% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2018, 5,880,843 common shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 17, 2019, an additional 1,606,001 common shares were issued under the Reinvestment Plan.

# SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2018, APUC recorded $9.5 million in total share-based compensation expense as compared to $8.4 million for the same period in 2017. There is no tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2018, total unrecognized compensation costs related to non-vested options and share unit awards were $1.2 million and $8.2 million, respectively, and are expected to be recognized over a period of 1.64 and 1.60 years, respectively.

## Stock Option Plan

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

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the twelve months ended December 31, 2018, the Company granted 1,166,717 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of C$12.80, the market price of the underlying common share at the date of grant. During the year, executives of the Company exercised 1,493,694 stock options at a weighted average exercise price of C$10.66 in exchange for common shares issued from treasury and 95,517 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at December 31, 2018, a total of 6,292,642 options are issued and outstanding under the stock option plan.

## Performance Share Units

APUC issues performance share units ("PSUs") and restricted share units ("RSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2018, the Company granted (including dividends and performance adjustments) 791,524 PSUs and RSUs to executives and employees of the Company. During the year, the Company settled 285,551 PSUs, of which 142,473 PSUs were exchanged for common shares issued from treasury and 143,078 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2018, a total of 68,869 PSUs were forfeited.

As at December 31, 2018, a total of 1,392,132 PSUs and RSUs are granted and outstanding under the PSU and RSU plan.

## Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive all or any portion of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2018, the Company issued 86,750 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2018, a total of 380,656 DSUs had been granted under the DSU plan.

## Bonus Deferral Restricted Share Units

During the year, the Company introduced a new bonus deferral restricted share units ("RSUs") program to certain employees. The eligible employees have the option to receive a portion or all of their annual bonus payment in RSUs in lieu of cash. The RSUs provide for settlement in shares, and therefore these options are accounted for as equity awards. During the twelve months ended December 31, 2018, 131,611 RSUs were issued (including RSUs in lieu of dividends) to employees of the Company. During the year, the Company settled 4,545 RSUs in exchange for 2,111 common shares issued from treasury, and 2,434 RSUs were settled at their cash value as payment for tax withholdings related to the settlement of the RSUs.

## Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the twelve months ended December 31, 2018, the Company issued 252,698 common shares to employees under the ESPP.

As at December 31, 2018, a total of 1,032,251 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 liquidity 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

**Equity-method investments**

The Company entered in a number of transactions with equity-method investees in 2018 and 2017 (see *Note 8* in the annual audited consolidated financial statements).

The Company provides administrative and development services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $11.4 million in 2018 as compared to $4.7 million during the same period in 2017 (see *Note 8(d)* and *8(e)* in the annual audited consolidated financial statements).

Subject to certain limitations, Atlantica has a right of first offer on any proposed sale, transfer or other disposition by AAGES (other than to APUC) of its interest in infrastructure facilities that are developed or constructed in whole or in part by AAGES under long-term revenue agreements. Similarly, Atlantica has rights, subject to certain limitations, with respect to any proposed sale, transfer or other disposition of APUC's interest, not held through AAGES, in infrastructure facilities that are developed or constructed in whole or in part by APUC outside of Canada or the United States under long-term revenue agreements. There were no such transactions in 2018 (see *Note 8(a)* and *8(b)* in the annual audited consolidated financial statements).

**Redeemable non-controlling interests**

In 2018, contributions of $305.0 million were received from AAGES for preference shares of a wholly consolidated subsidiary of the Company (see *Note 8(a)* and *Note 17* in the annual audited consolidated financial statements) .

**Long Sault Hydro Facility**

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

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

# ENTERPRISE RISK MANAGEMENT

The Corporation is subject to a number of risks and uncertainties, certain of which are described below. A risk is the possibility that an event might happen in the future that could have a negative effect on the financial condition, financial performance or business of the Corporation. The actual effect of any event on the Corporation's business could be materially different from what is anticipated or described below. The description of risks below does not include all possible risks.

Led by the Chief Compliance and Risk Officer, the Corporation has an established enterprise risk management, or ("ERM"), framework. The Corporation's ERM framework follows the guidance of ISO 31000:2009 and the COSO Enterprise Risk Management - Integrated Framework. The Corporation's ERM framework is intended to systematically identify, assess and mitigate the key strategic, operational, financial and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's Board-approved ERM policy details the Corporation's risk management processes, risk appetite and risk governance structure.

As part of the risk management process, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board's Risk Committee periodically.

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

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 set out in the Company's most recent AIF available on SEDAR.

## Treasury Risk Management

**Downgrade in the Company's Credit Rating Risk**

APUC has a long term consolidated corporate credit rating of BBB from S&P, a BBB rating from DBRS and a BBB issuer rating from Fitch. APCo, the primary operating company of the Liberty Power Group, has a BBB issuer rating from S&P, BBB issuer rating from DBRS and a BBB issuer rating from Fitch. LUCo, parent company for the Liberty Utilities Group, has a corporate credit rating of BBB from S&P and a BBB issuer rating from Fitch. Debt issued by Liberty Finance, a special purpose financing entity of LUCo, has a rating of BBB (high) from DBRS and BBB+ from Fitch. Empire has a BBB issuer rating from S&P and a Baa1 issuer rating from Moody's.

The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by such entities. 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. Any such downgrade could also adversely impact the market price of the outstanding securities of the Company. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and Fitch, BBB (low) or above for DBRS and Baa3 or above for Moody's), 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.

The Company is not adopting or endorsing such ratings, and such ratings do not indicate APUC's assessment of its own ability to pay the interest or principal of debt securities it issues. The Company is providing such ratings only to assist with the assessment of future risks and effects of ratings on the Company's financing costs.

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.

**Capital Markets and Liquidity Risk**

As at December 31, 2018, the Company had approximately $3,337.3 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

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

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

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

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

**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 significant interest rate risk in the short to medium term time horizon.

Borrowings subject to variable interest rates can vary significantly from month to month, quarter to quarter and year to year. 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.

Based on amounts outstanding as at December 31, 2018, the impact to interest expense from changes in 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, 2018. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Utilities Group's revolving credit facility is subject to a variable interest rate and had $97.0 million outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.0 million annually;
- The Liberty Utilities Group's commercial paper program is subject to a variable interest rate and had $6.0 million outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually;
- The Liberty Power Group's revolving credit facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would not impact interest expense; and
- The corporate term facilities are subject to a variable interest rate and had $321.8 million outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $3.2 million annually.

To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Liberty Power Group entered into a 10-year forward starting swap to fix the underlying interest rate for the anticipated refinancing of its C$135.0 million bond which matured in July 2018. On July 24, 2018, the Company amended and extended the forward-starting date of the interest rate swap to begin on March 29, 2019. Subsequent to year-end and concurrent with the issuance of C$300.0 million of senior unsecured debentures on January 29, 2019 this swap was unwound and settled.

**Tax Risk and Uncertainty**

The Company is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which APUC does business could adversely affect the Company's results from operations, our return to shareholders, and cash flow.

The Company cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Company, including with respect to claimed expenses and the cost amount of the Company's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect our results of operations and financial position.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or APUC is unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that APUC is committed to complete. In addition, the Liberty Power Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Company from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

*U.S. Tax Reform*

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Company (See *U.S. Tax Reform*). The U.S. Department of Treasury has released proposed regulations related to business interest expense limitations, Base Erosion Anti-Abuse Tax ("BEAT"), and anti-hybrid structures as part of the implementation of U.S. Tax Reform. These proposed regulations are not final and are subject to change in the regulatory review process which is expected to be completed later in 2019. The timing or impacts of any future changes in tax laws, including the impacts of proposed regulations, cannot be predicted. As a result, there may be future impacts on the results of operations, financial condition and cash flows of the Company beyond those described herein.

**Credit/Counterparty Risk**

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

The following chart sets out the Company's 10 largest customers and their credit ratings:

| Counterparty | Credit Rating [1] | Approximate Annual Revenues | Percentage of APUC Revenue |
|---|---|---|---|
| PJM Interconnection LLC | Aa2 | $ 25.5 | 1.5% |
| Manitoba Hydro | A+ | 21.0 | 1.3% |
| Hydro Quebec | AA- | 21.4 | 1.3% |
| Commonwealth Edison | BBB | 19.4 | 1.2% |
| Xcel Energy | A3 | 17.2 | 1.0% |
| Pacific Gas and Electric Company | D | 22.0 | 1.3% |
| Wolverine Power Supply | A | 24.2 | 1.5% |
| Independent Electricity System Operator of Ontario | A+ | 16.3 | 1.0% |
| Electric Reliability Council of Texas (ERCOT) | Aa3 | 11.9 | 0.7% |
| Connecticut Light and Power | A3 | 23.1 | 1.4% |
| **Total** | | **$ 202.0** | |

[1] Ratings by DBRS, Moody's, or S&P.

Liberty Power Group's revenues are approximately 14% of total Company revenues. Approximately 84% of the Liberty Power Group's revenues are earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS.

The remaining revenue of the Company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total $21.5 million which is spread over approximately 164,000 connections, resulting in an average outstanding balance of approximately $130 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total $35.1 million, while electric distribution systems accounts receivable balances related to the electric utilities total $150.2 million. The natural gas and electrical utilities both derive over 85% of their revenue from residential customers and have a per connection average outstanding balance of $104 dollars and $565 dollars respectively

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

**Market Price Risk**

The Liberty Power 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 Liberty Power 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 Liberty Power 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 Liberty Power 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 Liberty Power Group for its operating facilities along with residual exposures to the market are detailed below:

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

A second hedge for the Sandy Ridge Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 73% 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 42,000 MW-hrs annually.

A third hedge for the Sandy Ridge Wind Facility will commence on January 1, 2024, for a five year period. The financial hedge commitment is declining over the five year period and is structured to hedge 74% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates in 2024, stepping down to 19% by 2028. The annual unhedged production based on long term projected averages is approximately 41,000 MW-hrs in 2024, stepping up to 128,000 MW-hrs by 2028.

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

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each $10 per MW-hr change in market prices would result in a change in revenue of approximately $2.0 million for the year.

A second hedge for the Minonk Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 72% 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 189,000 MW-hrs annually.

A third hedge for the Minonk Wind Facility will commence on January 1, 2024, for a one year period. The financial hedge is structured to hedge 37% 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 423,000 MW-hrs annually.

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 Liberty Power 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, 2018, the Liberty Power Group had entered into hedges with a cumulative notional quantity of 7,440 MW-hrs.

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

The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in Atlantica, with changes in fair value reflected in the annual audited consolidated statement of operations. As a result, each dollar change in the traded price of Atlantica shares will correspondingly affect the Company's Net Earnings by approximately $41.6 million.

**Commodity Price Risk**

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

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 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 $0.5 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 190,000 MW-hrs in fiscal 2019, of which 181,000 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 41,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region not be able to reach the estimated 190,000 MW-hrs. The risk associated with the expected market purchases of 41,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 27% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $77 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 $0.3 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 California Public Utilities Commission ("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 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 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 18% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual state commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs. Similar to the Midstates Gas Systems, the Empire Gas System serves customers in Missouri, and also implements a commodity hedging program designed to hedge 70 to 90% of its winter demand inclusive of storage volumes withdrawn during the winter period. All related costs are embedded in approved rates and are passed-through to customers in the PGA. The Empire Gas System is permitted to file an Actual Cost Adjustment ("ACA") once a year which also includes a PGA filing. In addition to the ACA filing, three more optional PGA filings are allowed during the year. The gas segment's ACA year is from September 1 to August 31 for each year.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia Public Service Commission ("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 Georgia PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 41% of its 2018 generation fuel supply need through coal. Approximately 98% of its 2018 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2019. These contracts and inventory on hand satisfy approximately 50% of anticipated fuel requirements for 2019 for the Asbury Coal Facility.

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

## 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, natural disasters, interruption in supply chain and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Liberty Utilities 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 Liberty Utilities 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 Liberty Utilities 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.

The Liberty Power Group's hydro assets utilize dams to pond water for generation and if the dams fail/breach 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 Liberty Power 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, which will lower wind levels below our PPA and hedge minimum production levels. The wind units can experience failures in the turbine blades or in the supporting towers. Production risks associated with the wind turbine generators failures is mitigated by properly maintaining the units, using long term maintenance agreements with the turbine O&Ms 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 Liberty Power Group's Thermal Energy Division uses natural gas and oil, and produces 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 facilities are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged in part by long term purchases.

All of the Liberty Power 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.

These risks are mitigated through the diversification of APUC's operations, both operationally and geographically, the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance, an active Enterprise Risk Management program 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 of Liberty Power Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The Liberty Utilities Group operates in 12 different states and therefore is subject to regulation from 12 different regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

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

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, the Act reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates has had a significant impact on regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. Throughout the course of 2018, the Liberty Utilities Group obtained orders from the majority of its principal regulators covering approximately 93% of customers, resulting in the reduction of customer rates in connection with the reduction in tax rates. Collectively, the orders represent an annualized aggregate reduction in utility revenues of approximately $35 million, of which approximately $18 million has been realized in 2018. Since the Company has not yet received rate orders addressing U.S. Tax Reform for all of its utilities, the full impact of rate reductions related to U.S. Tax Reform is not known.

*Condemnation Expropriation Proceedings*

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

*Apple Valley Condemnation Proceedings*

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp ("Liberty Apple Valley"). The lawsuit will be adjudicated in phases. In the first phase, the Court will determine whether to allow the taking by the Town; under California law, the taking will be allowed unless Liberty Apple Valley proves there is not a "public necessity" for the taking. If Liberty Apple Valley prevails, the case is concluded and the Town will be required to compensate Liberty Apple Valley for its litigation expenses. However, if the Court determines that the taking is allowed, there will be a second phase of the trial in which a jury will determine the amount of compensation owed for the taking based upon the fair market value of the assets being condemned. The Court has been briefed on a related California Environmental Quality Act ("CEQA") lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 denying Liberty Apple Valley's CEQA claim. As a result, the condemnation case will proceed. At present, discovery related to the first phase of the trial is ongoing. The trial date has been set for September 30, 2019 and is expected to last approximately four weeks. If, following that trial, there is a need for a second phase to determine compensation, that trial can be expected to occur six to twelve months after the conclusion of the first phase.

**Acquisition Risk**

Part of the Company's business strategy is to acquire new generating stations and existing regulated utilities. The Company's acquisition strategy introduces exposures inherent to such transactions that may adversely affect the results of an acquisition, including delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies. 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.

When acquisitions occur, significant demands can 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.

**International Investment Risk**

The Company's investment in Atlantica exposes the Company to certain risks that are particular to Atlantica's business and the markets in which Atlantica operates.

Atlantica owns, manages and acquires renewable energy, conventional power, electric transmission lines and water assets in certain jurisdictions where the Company may not operate. The Company, through its investment in Atlantica, is indirectly exposed to certain risks that are particular to the markets in which it operates, including, but not limited to, risks related to: conditions in the global economy; changes to national and international laws, political, social and macroeconomic risks relating to the jurisdictions in which Atlantica operates, including in emerging markets, which could be subject to economic, social and political uncertainties; anti-bribery and anti-corruption laws and substantial penalties and reputational damage from any non-compliance therewith; significant currency exchange rate fluctuations; Atlantica's ability to identify and/or consummate future acquisitions on favourable terms or at all; Atlantica's inability to replace, on similar or commercially favourable terms, expiring or terminated offtake agreements; termination or revocation of Atlantica's concession agreements or PPAs; and various other factors. These risks could affect the profitability and growth of Atlantica's business, and ultimately the profitability of the Company's anticipated investment therein.

The Company's international acquisition, development, construction and operating activities, including through the AAGES joint venture, expose the Company to similar risks and could likewise affect the profitability, financial condition and growth of the Company.

**Joint Venture Investment Risk**

The Company has, and will in the future continue to have, an equity interest of 50% or less in certain projects. As a result, the Company will not control such projects and may be subject to the decision-making of third parties, whose interests may not always be aligned with those of the Company. This may limit the Company's flexibility and financial returns with respect to these projects.

The Company has, and will in the future continue to have, an interest in projects over which it does not have sole control. Despite having a 50% equity stake in AAGES, the joint venture involves risks, including, among others, a risk that Abengoa:

- may have economic or business interests or goals that are inconsistent with the Company's economic or business interests or goals;
- may take actions contrary to the Company's policies or objectives with respect to the Company's investments;
- may contravene applicable anti-bribery laws that carry substantial penalties for non-compliance and could cause reputational damage and a material adverse effect on the business, financial position and results of operations of AAGES and the Company;
- may have to give its consent with respect to certain major decisions;
- may become bankrupt, limiting its ability to meet calls for capital contributions and potentially making it more difficult to refinance or sell projects;
- may become engaged in a dispute with the Company that might affect the Company's ability to develop a project; or
- may have competing interests in the Company's markets that could create conflict of interest issues.

Further, the Company will not have sole control of certain major decisions relating to the projects that the Company owns or pursues through AAGES, including, among others, decisions relating to funding and transactions with affiliates. The Company's involvement with AAGES may also present a reputational risk, including from the reputation of Abengoa.

AAGES has obtained a 3 year secured credit facility in the amount of $306.5 million ("AAGES Credit Facility"), which is collateralized through a pledge of the Atlantica shares. A collateral shortfall would occur if the net obligation as defined in the agreement would equal or exceed 50% of the market value of the Atlantica shares. In the event of a collateral shortfall AAGES is required to post additional collateral in cash to reduce the net obligation to 40% of the total collateral provided ("Collateral Reset Level"). If AAGES were unable to fund the collateral shortfall, the AAGES Credit Facility lenders hold the right to sell Atlantica stock to reduce the facility to the Collateral Reset Level. The AAGES Credit Facility is repayable on demand if Atlantica ceases to be a public company. If AAGES were unable to repay the amounts owed, the lenders would have the right realize on their collateral (see *Note 8(a)* in the annual audited consolidated financial statements).

**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.

In conjunction with acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal or decommissioning of power generating facilities; (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 mains 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.

**Cycles and Seasonality**

*Liberty Utilities Group*

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

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

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

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate review proceedings. While not all regulatory jurisdictions have approved mechanisms to mitigate demand fluctuations, to date, the Liberty Utilities Group has successfully obtained regulatory approval to implement such decoupling mechanisms in 6 of 12 states. An example of such a mechanism is seen at the Peach State Gas System in Georgia, where 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.

*Liberty Power Group*

The Liberty Power 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 Liberty Power Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall through spring period, 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 Liberty Power 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.

**Development and Construction Risk**

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

*Risks Specific to Renewable Generation Projects*:

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

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

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

**Litigation Risks and Other Contingencies**

APUC and certain of its subsidiaries are involved in various litigation, claims and other legal and regulatory 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.

*Claim by Gaia Power Inc.*

On October 30, 2018, Gaia Power Inc. ("Gaia") commenced an action in the Ontario Superior Court of Justice against APUC and certain of its subsidiaries, claiming damages of not less than $345 million and punitive damages in the sum of $25 million. The action arises from Gaia's 2010 sale, to a subsidiary of APUC, of Gaia's interest in certain proposed wind farm projects in Canada. Pursuant to a 2010 royalty agreement, Gaia is entitled to royalty payments if the projects are developed and achieve certain agreed targets.

APUC believes that the claims are without merit, and intends to vigorously defend the action.

See further discussion of claims made by or against APUC or its subsidiaries in *Regulatory Risk*.

**Cybersecurity Risk**

The Company's information technology systems may be vulnerable to potential risks from cybersecurity attacks. Attacks can be caused by malware, viruses, email attachments, acts of war or terrorism and can originate from individuals from both inside and outside the organization. An attack could result in service disruptions, system failures, the disclosure of personal customer and employee information, and could lead to an adverse effect on the Company's financial performance. A breach of personal or confidential information may also occur as a result of non-cyber means, such as breach of physical security and device theft. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

**Energy Consumption and Advancement in Technologies Risk**

The Liberty Utilities Group's operations are subject to changes in demand for energy which are impacted by general economic conditions, customer's focus on energy efficiency, and advancements in new technologies.

The Liberty Utilities Group is actively involved in working with governments and customers to ensure these changes in consumption do not negatively impact the services provided. Furthermore, through its strategic initiatives the Liberty Utilities Group is constantly looking for ways to maintain the Company's competitive advantage.

**Uninsured Risk**

The Company maintains insurance for accidental loss and potential liabilities to third parties in accordance with the industry practice. However, there are certain elements of the Liberty Utilities Group's regulated utilities that are not fully insured as the cost of the coverage is not economically viable. In the event that a liability event or loss is not covered through insurance the Liberty Utilities Group would apply to their respective regulator to request recovery through increased customer rates. Cost recovery through this mechanism is subject to regulatory approval and is therefore uncertain.

Insurance coverage for the rest of the Company is also subject to policy conditions and exclusions, coverage limits, and various deductibles, and not all types of liabilities and losses may be covered by insurance, in which case the Company may be financially exposed.

## QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended December 31, 2018:

| (all dollar amounts in $ millions except per share information) | 1st Quarter 2018 | 2nd Quarter 2018 | 3rd Quarter 2018 | 4th Quarter 2018 |
|---|---|---|---|---|
| Revenue | $ 494.8 | $ 366.2 | $ 366.5 | $ 419.9 |
| Net earnings attributable to shareholders | 17.6 | 65.5 | 57.9 | 44.0 |
| Net earnings per share | 0.04 | 0.14 | 0.12 | 0.09 |
| Adjusted Net Earnings[1] | 141.1 | 50.9 | 49.7 | 70.5 |
| Adjusted Net Earnings per share[1] | 0.30 | 0.11 | 0.10 | 0.14 |
| Adjusted EBITDA[1] | 279.2 | 160.3 | 166.9 | 196.9 |
| Total assets | 8,941.8 | 8,920.7 | 9,072.6 | 9,389.0 |
| Long term debt[2] | 3,832.7 | 3,448.1 | 3,561.3 | 3,337.3 |
| Dividend declared per common share | $ 0.12 | $ 0.13 | $ 0.13 | $ 0.13 |

| | 1st Quarter 2017 | 2nd Quarter 2017 | 3rd Quarter 2017 | 4th Quarter 2017 |
|---|---|---|---|---|
| Revenue | $ 421.7 | $ 337.0 | $ 353.7 | $ 409.5 |
| Net earnings attributable to shareholders | 19.3 | 35.3 | 47.7 | 47.2 |
| Net earnings per share | 0.05 | 0.09 | 0.12 | 0.11 |
| Adjusted Net Earnings[1] | 66.5 | 39.5 | 52.0 | 67.0 |
| Adjusted Net Earnings per share[1] | 0.19 | 0.09 | 0.13 | 0.16 |
| Adjusted EBITDA[1] | 192.3 | 147.1 | 164.2 | 185.8 |
| Total assets | 8,174.9 | 8,113.3 | 8,258.6 | 8,395.6 |
| Long term debt[2] | 3,586.5 | 3,404.5 | 3,553.7 | 3,080.5 |
| Dividend declared per common share | $ 0.12 | $ 0.12 | $ 0.12 | $ 0.12 |

[1] See *Non-GAAP Financial Measures*

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

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

Quarterly revenues have fluctuated between $337 million and $494.8 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from Canadian operations.

Quarterly net earnings attributable to shareholders have fluctuated between $17.6 million and $65.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

## SUMMARY FINANCIAL INFORMATION OF ATLANTICA

The Company has a 41.5% interest in the common stock of Atlantica. APUC accounts for its interest in Atlantica using the fair value method (see *Note 8(a)* in the annual audited consolidated financial statements). The summary financial information of Atlantica in the following table is derived from the audited consolidated financial statements of Atlantica as of December 31, 2018 and 2017 and for the years then ended which are reported in U.S. dollars and were prepared using International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS"). The recognition, measurement and disclosure requirements of IFRS differ from U.S. GAAP as applied by the Company.

| (all dollar amounts in $ millions) | 2018 | 2017 |
|---|---|---|
| Revenue | $ **1,043.8** | $ 1,008.4 |
| Profit (loss) for the year | **55.3** | (104.9) |
| Total non-current assets | **8,791.3** | 9,350.4 |
| Total current assets | **1,127.7** | 1,141.9 |
| Total non-current liabilities | **7,423.8** | 8,096.5 |
| Total current liabilities | **739.1** | 500.4 |

## DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2018, under the supervision of and with the participation of APUC's Chief Executive Officer ("CEO") and 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, 2018, APUC's disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by APUC in reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

## MANAGEMENT REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

The Company's internal control over financial reporting framework 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 the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) 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 Company's consolidated financial statements.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, based on the framework established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment 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 assessment, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2018 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of APUC.

## CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

For the twelve months ended December 31, 2018, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

## INHERENT LIMITATIONS ON EFFECTIVENESS OF CONTROLS

Due to its inherent limitations, disclosure controls and procedures or internal control over financial reporting may not prevent or detect all misstatements based on error of fraud. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

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

### Consolidation and Variable Interest Entities

The Company uses judgment to assess whether its operations or investments represent variable interest entities ("VIEs"). In making these evaluations, management considers a) the sufficiency of the investment's equity at risk, b) the existence of a controlling financial interest, and c) the structure of any voting rights. In addition, management considers the specific facts and circumstances of each investment in a VIE when determining whether the Company is the primary beneficiary. The factors that management takes into consideration include the purpose and design of the VIE, the key decisions that affect its economic performance, and whether the Company has the power to direct the activities that would most significantly affect the economic performance of the VIE. Management's judgment is also required to determine whether the Company has the right to receive benefits or the obligation to absorb losses of the VIE. Based on the judgments made, the Company will consolidate the VIE if it determines that it is the primary beneficiary.

### 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.

In 2018 and 2017, Management assessed qualitative and quantitative factors for each of the reporting units that were allocated goodwill. No goodwill impairment provision was required.

### Measurement of Deferred Taxes

On December 22, 2017, the U.S. government enacted the Tax Cuts and Jobs Act (the "Act"). The Act made broad and complex changes to the U.S. tax code which impacted 2017 including, but not limited to, reducing the U.S. federal corporate tax rate from 35% to 21% and introducing 100% expensing for certain capital expenditures, excluding regulated utilities, made after September 27, 2017. Management's judgment is required to measure the deferred taxes assets and liabilities at the enactment date based on these changes. Where requirements of the implementation of the new Act are incomplete, management uses judgments and assumptions to calculate a reasonable provisional amount to include in the Company's financial statements.

## Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Although at this time Management considers it more likely than not that it will have sufficient taxable income to realize the deferred tax assets, there can be no assurance that the Company will generate sufficient taxable income in the future to utilize these deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. Management's assessment has been impacted by the tax reform discussed above.

## Accounting for Rate Regulation

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

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

## Unbilled Energy Revenues

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

The Financial Accounting Standards Board ("FASB") issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. The Company adopted the new standard using the modified retrospective method effective January 1, 2018. The adoption of Topic 606 did not have a material impact on the consolidated financial statements and the pattern of revenue recognition.

## Derivatives

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

## Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2018) recently released by the Society of Actuaries adjusted to reflect the 2018 Social Security Administration ultimate improvement rates.

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, for reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. The Company adopted this guidance effective January 1, 2018. Following the effective date of this Accounting Standards Update ("ASU"), the Company's regulated operations only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences exist. The Company has applied the practical expedient for retrospective application on the statement of operations.

**Sensitivities**

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2018 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.

| | 2018 Pension Plans | | 2018 OPEB Plans | |
|---|---|---|---|---|
| (all dollar amounts in $ millions) | Accrued Benefit Obligation | Net Periodic Pension Cost | Accumulated Postretirement Benefit Obligation | Net Periodic Postretirement Benefit Cost |
| Discount Rate | | | | |
| 1% increase | (43.9) | (4.1) | (22.8) | (1.0) |
| 1% decrease | 53.6 | 3.9 | 29.0 | 2.5 |
| Future compensation rate | | | | |
| 1% increase | 0.3 | 0.6 | — | — |
| 1% decrease | (0.3) | (2.7) | — | — |
| Expected return on plan assets | | | | |
| 1% increase | — | (3.5) | — | (1.2) |
| 1% decrease | — | 3.5 | — | 1.4 |
| Life expectancy | | | | |
| 10% increase | 26.1 | 2.8 | 15.1 | 1.8 |
| 10% decrease | (27.7) | (4.0) | (14.5) | (1.4) |
| Health care trend | | | | |
| 1% increase | — | — | 28.0 | 4.4 |
| 1% decrease | — | — | (22.2) | (2.6) |

## Business Combinations

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

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

Additional disclosure of APUC's critical accounting estimates is also available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar, and on the APUC website at www.AlgonquinPowerandUtilities.com.

**Exhibit 99.4**

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the reference to our firm under the caption “Experts” and to the use in this Annual Report on Form 40-F filed with the United States Securities and Exchange Commission of our reports dated February 28, 2019, with respect to the consolidated balance sheets of Algonquin Power & Utilities Corp. (the “Company”) as at December 31, 2018 and 2017, 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, 2018, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2018.

We also consent to the incorporation by reference of our reports dated February 28, 2019 in the Registration Statements on Form S-8 (File No. 333-177418), Form S-8 (File No. 333-213648), Form S-8 (File No. 333-213650), Form S-8 (File No. 333-218810), Form F-10 (File No. 333-216616), Form F-10 (File No. 333-227245), Form F-3 (File No. 333-220059) and Form F-3 (File No. 333-227246), with respect to the consolidated balance sheets of the Company as at December 31, 2018 and 2017, 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, 2018, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2018.

/s/ Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants

Toronto, Canada
February 28, 2019

**Exhibit 99.5**

**CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002**

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 28, 2019

By: "/s/" Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

**Exhibit 99.6**

**CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002**

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 28, 2019

By: "/s/" David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

**Exhibit 99.7**

**CERTIFICATION PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: February 28, 2019

By: "/s/" Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

**Exhibit 99.8**

**CERTIFICATION PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: February 28, 2019

By: "/s/" David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer