# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 40 F

[Check one]

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

**OR**

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

**For the fiscal year ended December 31, 2016** **Commission File Number 000-53808**

# 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)**

**C T 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 | Toronto Stock Exchange |
| | 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:

x **Annual Information Form** x **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, 2016, there were 274,087,018 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.

**No** o

**Yes** x

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, 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 and post such files).

**Yes** x **No** o

---

## ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2016 is filed as Exhibit 99.1 to this annual report on Form 40-F.

## AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of Algonquin for the fiscal year ended December 31, 2016 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, 2016 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" (page 50) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2016, 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

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Algonquin'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 Algonquin's internal control over financial reporting as of December 31, 2016, based on the framework established in Internal Control- Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that Algonquin maintained effective internal control over financial reporting as of December 31, 2016.

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, 2016, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2016.

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

The attestation report of Ernst & Young, LLP, the independent registered public accounting firm of Algonquin, on the Company's internal control over financial reporting as of December 31, 2016, 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 "Internal Controls Over Financial Reporting" (page 50) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2016, 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. The SEC has indicated that the designation of Christopher Ball and Dilek Samil as audit committee financial experts does not make any 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 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” (page 73) in the Annual Information Form for the fiscal year ended December 31, 2016, 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 year ended December 31, 2016 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” (page 38) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2016, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

## IDENTIFICATION OF THE AUDIT COMMITTEE

The information provided under the heading “Audit Committee” (page 72) 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, 2016, filed as Exhibit 99.1 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 MD&A. The terms “Adjusted Net Earnings”, “Adjusted Funds from Operations”, "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under GAAP. There is no standardized measure of “Adjusted Net Earnings”, "Adjusted EBITDA", “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “Adjusted Net Earnings”, "Adjusted EBITDA", “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

## CAUTION CONCERNING FORWARD LOOKING STATEMENTS

Certain statements included in this annual report on Form 40-F and the exhibits attached hereto contain forward-looking information within the meaning of the United States Private Securities Litigation Reform Act of 1995 and applicable Canadian securities legislation. These statements reflect the views of Algonquin with respect to future events, based upon assumptions relating to, among others, the performance of Algonquin’s assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of Algonquin, its future plans and its dividends to shareholders. Statements containing expressions such as “outlook”, “believe”, “anticipate”, “continue”, “could”, “expect”, “may”, “will”, “project”, “estimate”, “intend”, “plan” and similar expressions generally constitute forward looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require Algonquin to make assumptions and involve inherent risks and uncertainties. Algonquin cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that Algonquin’s actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the volatility of world financial markets; the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; the state of the

Canadian and the United States economies and accompanying business climate as well as those risk factors discussed or referred to in the Management's Discussion and Analysis for the fiscal year ended December 31, 2016, filed as Exhibit 99.3 to this annual report on Form 40-F and the Annual Information Form for the fiscal year ended December 31, 2016, filed as Exhibit 99.1 to this annual report on Form 40-F. Algonquin cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Algonquin reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin believes that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of these dates. Algonquin is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

## MINE SAFETY DISCLOSURE

Not applicable.

## INTERACTIVE DATA FILE

The required disclosure for the fiscal year ended December 31, 2016 is filed as Exhibit 101 to this annual report on Form 40-F.

## COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

Algonquin is subject to corporate governance requirements prescribed under applicable Canadian corporate governance practices ("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 the 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).

Section 303A.02 of the NYSE Listed Company Manual 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 National Instrument 52-110 *Audit Committees* and Rule 10A-3 of the Securities Exchange Act of 1934.

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) 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 the listed company be given the opportunity to vote on all equity-compensation plans and material revisions thereto. Canadian Rules generally require that shareholders approve all equity compensation plans, but the Canadian Rules are not identical to the NYSE Rules. Algonquin complies with Canadian Rules.

Section 303A.09 of the NYSE Listed Company Manual requires that, amongst other things, Algonquin's governance guidelines include provisions relating to director compensation guidelines and director orientation and continuing education. Algonquin has adopted corporate governance guidelines and its Board Mandate, in compliance with the Canadian Rules. However, Algonquin's corporate governance guidelines do not include provisions relating to director compensation guidelines or director orientation and continuing education.

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.

## 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, thereunto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 10, 2017

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

**EXHIBIT INDEX**

| | |
|---|---|
| 99.1 | Annual Information Form for the year ended December 31, 2016. |
| 99.2 | Audited Annual Financial Statements for the year ended December 31, 2016. |
| 99.3 | Management's Discussion & Analysis for the year ended December 31, 2016. |
| 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. |
| 99.6 | Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 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. |




# ALGONQUIN POWER & UTILITIES CORP.

## ANNUAL INFORMATION FORM

March 10, 2017

# Table of Contents


1. CORPORATE STRUCTURE 3
1.1 Name, Address and Incorporation 3
1.2. Intercorporate Relationships 3
1.2.1 Subsidiaries 3
1.2.2 Other Interests in Energy Related Developments 8

2. GENERAL DEVELOPMENT OF THE BUSINESS 9
2.1 General 9
2.1.1 Business Strategy 9
2.2 Three Year History and Significant Acquisitions 10
2.2.1 Fiscal 2014 10
2.2.2 Fiscal 2015 13
2.2.3 Fiscal 2016 14
2.3 Recent Developments - 2017 16

3. DESCRIPTION OF THE BUSINESS 17
3.1. Renewable Generation Group 18
3.1.1 Regulatory Regimes 18
3.1.2 Description of Operations 19
3.1.3 Specialized Skill 28
3.1.4 Competitive Conditions 28
3.1.5 Cycles & Seasonality 28
3.1.6 Customers 29
3.2 Liberty Utilities Group 29
3.2.1 Regulatory Regimes 29
3.2.2 Description of Operations 30
3.2.3 Specialized Skill 45
3.2.4 Competitive Conditions 45
3.2.5 Cycles & Seasonality 45
3.2.6 Customers 46
3.3 Related Party Transactions 47
3.4 Principal Revenue 47
3.5 Environmental Protection 47
3.6 Employees 48
3.7 Foreign Operations 48
3.8 Economic Dependence 48
3.9 Social or Environmental Policies 48
3.10 Credit Rating 49

4. ENTERPRISE RISK FACTORS 50
4.1. Treasury Risk Factors 50
4.1.1 Downgrade in the Corporation's Credit Rating Risk 50
4.1.2 Liquidity Risk 50
4.1.3 Tax Risk and Uncertainty 51
4.1.4 Credit/Counterparty Risk 51

# Table of Contents
# (Continued)


4.1.5 Foreign Currency Risk 52
4.1.6 Market Price Risk 52
4.1.7 Commodity Price Risk 53
4.1.8 Defined Benefit Pension Plan Risk 55
4.1.9 Substantial Indebtedness Relating to the Empire Acquisition 55
4.1.10 Interest Rate Risk 56
4.2 Operational Risk Factors 56
4.2.1 Mechanical and Operational Risks 56
4.2.2 Development and Construction Risk 56
4.2.3 Cycles and Seasonality Risk 57
4.2.4 Energy Efficiency Risk 57
4.2.5 Cyber Security 57
4.2.6 Environmental Risks 57
4.2.7 Asset Retirement Obligations 58
4.2.8 Dependence Upon Key Customers 58
4.2.9 Personnel and Labour 58
4.2.10 Obligations to Serve 59
4.2.11 Litigation risks and other contingencies 59
4.3 Regulatory Climate and Permitting Risks 59
4.4 Acquisitions and Divestitures 60

5. DIVIDENDS 61
5.1 Dividend Reinvestment Plan 61

6. DESCRIPTION OF CAPITAL STRUCTURE 62
6.1 Common Shares 62
6.2 Private Placements of Subscription Receipts and Common Shares to Emera 62
6.3 Preferred Shares 62
6.4 Convertible Debentures 64
6.4.1 Convertible Unsecured Subordinated Debentures 64
6.5 Employee Share Purchase Plan 64
6.6 Directors Deferred Share Units 64
6.7 Performance Share Units 65
6.8 Shareholders' Rights Plan 65
6.9 Stock Option Plan 65

7. MARKET FOR SECURITIES 68
7.1 Trading Price and Volume 68
7.1.1 Common Shares 68
7.1.2 Preferred Shares 69
7.2 Prior Sales 70
7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer 71

8. DIRECTORS AND OFFICERS 71
8.1 Name, Occupation and Security Holdings 71

# Table of Contents
# (Continued)


8.2 Audit Committee 74
8.2.1 Audit Committee Charter 74
8.2.2 Relevant Education and Experience 74
8.2.3 Pre-Approval Policies and Procedures 75
8.3 Corporate Governance, Risk and Compensation Committees 75
8.4 Bankruptcies 75
8.5 Potential Material Conflicts of Interest 75

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS 75
9.1 Legal Proceedings 75
9.2 Regulatory Actions 75

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 76

11. TRANSFER AGENTS AND REGISTRARS 76

12. MATERIAL CONTRACTS 76

13. INTERESTS OF EXPERTS 77

14. ADDITIONAL INFORMATION 77

SCHEDULE A- RENEWABLE - HYDROELECTRIC, SOLAR AND WIND FACILITIES A - 1

SCHEDULE B - THERMAL - BIOMASS, COGENERATION, AND DIESEL FACILITIES B - 1

SCHEDULE C - WASTEWATER AND WATER DISTRIBUTION FACILITIES C - 1

SCHEDULE D - ELECTRICAL DISTRIBUTION FACILITIES D - 1

SCHEDULE E - NATURAL GAS DISTRIBUTION FACILITIES E - 1

SCHEDULE F - MANDATE TO THE AUDIT COMMITTEE F - 1

SCHEDULE G - GLOSSARY OF TERMS G - 1


*All information contained in this Annual Information Form ("**AIF**") is presented as at* December 31, 2016*, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.*

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

This AIF may contain statements that, to the extent they are not recitations of historical facts, constitutes "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation, including the *United States Securities Act of 1933*, as amended, the *United States Securities Exchange Act of 1934*, as amended, and applicable Canadian Securities legislation. All forward-looking information and forward-looking statements are given pursuant to the "safe harbour" provisions of applicable securities legislation. 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 and forward-looking statements, although not all forward-looking information or forward-looking statements contain these identifying words. The forward-looking information and forward-looking statements reflect management's current beliefs and are based on information currently available to the Corporation's management.

Forward-looking information and forward-looking statements are included throughout this AIF, including among other places, under the heading "General Development of the Business", "Description of the Business" and "Legal Proceedings and Regulatory Actions". These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances.

Since forward-looking statements and forward-looking information relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. The Corporation (as defined in this AIF) cautions that although it believes that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements and forward-looking information. The forward-looking information and forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by such information or statements. Factors which could cause results or events to differ from current expectations include, but are not limited to: derivative financial instruments, including, but not limited to, hedging availability; commodity price and availability risk; foreign exchange risk; interest rate risk; commercial relationship risk; credit risk; labour risk; weather risk; regulatory risk; environmental risk; capital market risk, including, but not limited to, economic conditions, cost of financing, capital resources and liquidity risk; construction and development risks; the anticipated benefits of the acquisitions, including the Empire Acquisition (as defined in this AIF) may not materialize or may not occur within the time periods anticipated by the Corporation; impact of significant demands placed on the Corporation as a result of acquisitions; failure to repay the non-revolving credit facilities in favor of Algonquin in an aggregate amount of US$0.9 billion (the "Empire Acquisition Credit Facilities"); increased indebtedness of Algonquin after the closing of the Empire Acquisition; the Empire Acquisition and related financing, including the Debenture Offering (as defined in this AIF), could result in a downgrade of credit ratings of the Corporation, the Empire District Electric Company ("Empire") and/or their subsidiaries; historical and pro forma combined financial information may not be representative of future performance; potential undisclosed liabilities of Empire and its subsidiaries; ability to retain key personnel of an acquired company following its acquisition; operating and maintenance risks; risks associated with changes in economic conditions; developments in technology could reduce demand for electricity, gas and water; changes in customer energy usage patterns; risk of failure of information technology infrastructure and cybersecurity; disruption of fuel supply; natural disasters or other catastrophic events; impairment testing of certain long-lived assets could result in impairment charges; risks relating to the Debentures and the Common Shares (each as defined in this AIF); unanticipated maintenance and other expenditures; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks associated with pension plan performance and funding requirements; regulatory and government decisions including, but not limited to, changes to environmental, financial reporting and tax legislation and regulations; risk of loss of licences and permits; risk of loss of service area; market energy sales prices; changes to the regulation of rates that subsidiaries of the Corporation charge their utility customers; risk of condemnation; and adverse publicity and reputational risk.

Material risk factors include those set out in this AIF under "Enterprise Risk Factors". Readers are cautioned that such risks and uncertainties may cause APUC's actual results to vary materially from those expressed in, or implied by, the forward-looking statements and forward-looking information. Given these risks, undue reliance should not be placed on these forward-looking statements or forward-looking information. In addition, such statements and information are made based on information available and expectations as of the date of this AIF and such expectations may change after this date. APUC is not obligated to nor does it intend to update or revise any forward-looking statements or forward-looking information, whether as a result of new information, future developments or otherwise, except as required by law.

## Non-GAAP Financial Measures

The terms “Adjusted Net Earnings”, “Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization” (“Adjusted EBITDA”), “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this AIF. These terms are not recognized measures under GAAP. There is no standardized measure of “Adjusted Net Earnings”, "Adjusted EBITDA", “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; and 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 in APUC's most recent management's discussion and analysis ("MD&A") for the year ended December 31, 2016, which calculation and analysis is incorporated herein by reference.

## Use of Non-GAAP Financial Measures

Adjusted EBITDA

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

Adjusted net earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company’s operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor’s understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Adjusted funds from operations

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

Net Energy Sales

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

Net Utility Sales

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

Divisional Operating Profit

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

# 1. CORPORATE STRUCTURE

## 1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. (" **APUC**" or the "**Corporation**") 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"**) (the "**Unit Exchange Transaction**") and changed its name to Algonquin Power & Utilities Corp. (**"APUC"**). The head and principal 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 " **APUC**" or the "**Corporation**" include, for reporting purposes only, the direct or indirect subsidiary entities of APUC and partnership interests held by APUC and its subsidiary entities. Such use of "**APUC**" or the "**Corporation**" to refer to these other legal entities and partnership interests does not constitute a waiver by APUC or such entities or partnerships of their separate legal status for any purpose.

## 1.2 Intercorporate Relationships

### 1.2.1 Subsidiaries

The subsidiaries of APUC are grouped by two primary North American business units of the Corporation consisting of the Renewable Generation Group, and the Liberty Utilities Group . The principal holding for APUC's Renewable Generation Group is an investment in 100% of the issued and outstanding trust units of APCo. The principal holding for the Corporation's Liberty Utilities Group is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp. ("**LU Canada**"), a Canadian federal corporation, which owns all of the issued and outstanding common shares of Liberty Utilities (America) Co., a Delaware corporation, which owns all of the issued and outstanding common shares of Liberty Utilities (America) Holdco Inc., a Delaware corporation, which owns all of the membership interests in Liberty Utilities (America) Holdings LLC, a Delaware LLC, which owns all of the issued and outstanding shares of Liberty Utilities Co. ("**Liberty Utilities**"), a Delaware corporation, which owns the utility subsidiaries as well as the U.S. based transmission subsidiaries, principally Liberty Utilities (Pipeline & Transmission) Corp., a Delaware corporation. The Canadian transmission assets are held by Algonquin Power (Ontario Transmission) Inc., which is 100% owned by LU Canada. The ownership chains for both of these primary business operations of the Corporation are described below.

In regard to the Renewable Generation Group, the subsidiaries of APCo include the ownership chains of Algonquin Power Trust (" **APT**") and Algonquin Power (Canada) Holdings Inc. ("**APCH**"), APCo directly owns a 100% interest in Windlectric Inc. (" **Windlectric**"), a Canadian federal corporation that is developing a wind project in Ontario, and APCo owns 100% of the issued and outstanding shares of Cornwall Solar Inc. ("Cornwall Solar", which owns a solar power facility in Cornwall, Ontario (the "Cornwall Solar Facility"). APT's subsidiaries include the ownership chain of Algonquin Power Operating Trust ("**APOT**"), and APCH's subsidiaries include the ownership chain of Algonquin Power Fund (America) Inc. ("**APFA**"). In regard to the Liberty Utilities Group, Liberty Utilities has direct and indirect investments in entities owning electric distribution, natural gas distribution, and water distribution utility systems in California, Iowa, Illinois, Kansas, Missouri, Montana, Oklahoma, Arkansas, Georgia, Massachusetts and New Hampshire. Through its subsidiary, Liberty Utilities Sub Corp. ("Liberty SubCo"), Liberty Utilities has investments in entities that own water distribution and wastewater collection utility systems in Arizona, Illinois, Missouri, and Texas. In addition, Liberty Utilities (Pipeline & Transmission) Corp. and Algonquin Power (Ontario Transmission) Inc. are undertaking the development of transmission projects in the United States and Canada, respectively.

The following chart summarizes the major lines of business.

| Renewable Generation Group |
| --- |
| Hydro Electric Generation |
| Wind Power Generation |
| Solar Generation |
| Thermal Co-Generation |

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

The major chains are described below, including details on the legal entities that comprise these chains and the facilities they own. Additional information on the facilities is described in Schedules A, B, C, D, and E.

### (i) Renewable Generation Group

#### Renewable Generation Group Chain Entities

APCo is the sole beneficiary of APT, which owns all of the trust certificates of APOT. APCo also owns 100% of the Class A common shares of APCH, an Ontario corporation. All of the Class B common shares of APCH are owned by 2496838 Ontario Inc., an indirect subsidiary of APOT, and all of the Class C common shares of APCH are owned by St. Leon Wind Energy GP Inc. ("St. Leon GP"), another indirect APOT subsidiary. APCo also owns 100% of the issued and outstanding shares of Cornwall Solar, which owns the Cornwall Solar Project in Cornwall, Ontario and APCo directly owns a 50% ownership in Windlectric, a Canadian federal corporation that is developing a wind project in Ontario. APCo is also the sole owner of eleven Ontario numbered companies which hold various rights to a pipeline of pending solar projects in Ontario.

#### APT Group

APT forms part of the Renewable Generation Group. APT is an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. APT owns all of the trust units of APOT.

APT controls the entities that own some of the Canadian hydroelectric facilities. APT owns all of the trust units in KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997 in accordance with the laws of the Province of Alberta. APT directly owns a 2% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the "**Mont-Laurier Partnership**"), a Québec limited partnership, which owns the Mont-Laurier hydroelectric facility (the "**Mont-Laurier Hydro Facility**") and the Côte Ste.-Catherine hydroelectric generating facility (the "**Côte Ste.-Catherine Hydro Facility**"), while APCH owns the remaining 98% partnership interests, comprised of an 86.5% limited partnership interest and an 11.5% general partnership interest.

APT directly owns the Hydraska hydroelectrical generating facility (the "**Hydraska Hydro Facility**") and the Arthurville hydroelectrical generating facility (the "**Arthurville Hydro Facility**"), and owns both the limited partnership interests in and the general partner of Algonquin Power (Campbellford) Limited Partnership, an Ontario limited partnership which operates a 4 megawatt hydroelectric generating facility on the Trent River near Campbellford, Ontario (the "**Campbellford Hydro Facility**").

APT also controls the entities which own APUC's interests in two wind projects in Quebec. APT owns a 24.995% interest in Éoliennes Belle-Rivières, sociètè en commandite ("**Val-Éo Partnership**") which owns the 125 MW project located in the local municipality of Saint-Gideon de Grandmont (the "**Val-Éo Wind Project**"). A non-APUC related entity, Val-Éo Coop de solidarité, owns 74.995% of the Val-Éo Partnership. The remaining 0.01% interest in the Val-Éo Partnership is owned by a Quebec company, Éoliennes Belle-Rivières Inc., the general partner. The interests in Éoliennes Belle-Rivières Inc. are owned 75% by Val-Éo Coop de solidarité, and 25% by APT. APT indirectly owns and controls 50% of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation ("**Saint-Damase GP**") which owns the Saint-Damase wind facility (the "**Saint-Damase Wind Facility**"). The remaining 50% is owned by Corporation Municipal de Saint-Damase, a non-APUC related entity, which also owns 100% of the preferred shares issued by Saint-Damase GP.

In 2016, APT acquired a 75% interest in Red Lily Wind Energy Partnership (" **Red Lily Partnership**"), a Saskatchewan general partnership which owns a 25 MW wind facility near Moosomin, Saskatchewan. The remaining 25% interest in Red Lily Partnership is owned by two non-APUC related entities: C.C. Acquisition Corp. and Red Lily Wind Energy Corp.

## APOT Group

APOT is an unincorporated open ended trust created by a trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta. APOT is governed by a Second Amended and Restated Trust Indenture, effective December 8, 2014.

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the " **St. Leon Wind Facility**"). The St. Leon Wind Facility is owned by St. Leon Wind Energy LP, a Manitoba limited partnership ("**St. Leon LP**"). St. Leon LP is owned by its general partner, St. Leon GP, by St. Leon Wind Energy Trust, a Manitoba trust (" **St. Leon Trust**") and by AirSource Power Fund I LP, a Manitoba limited partnership ("**AirSource**"). St. Leon LP has also issued 100 Class B limited partnership units which were acquired by APUC on January 1, 2013 in exchange for newly issued APUC Series C preferred shares ("Series C Share"). St. Leon Trust and St. Leon GP are owned 100% by AirSource, the limited partner of which is Algonquin (AirSource) Power LP ("**AAP LP**") which holds a 99.99% limited partnership interest in the limited partnership, and which in turn is owned 99.99% by APOT as limited partner. APOT also controls the general partner of AAP LP, Algonquin (AirSource) GP Inc., an Ontario corporation which holds the remaining 0.01% general partnership interest. St. Leon GP is a Canadian corporation and St. Leon Trust is a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba. The AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively. St. Leon LP also owns 100% of 2496838 Ontario Inc., an Ontario corporation.

St. Leon LP directly owns a 99% limited partnership interest in St. Leon II Wind Energy LP (" **St. Leon II LP**"), a Manitoba partnership which owns the 16.5 MW wind facility (the "**St. Leon II Wind Facility**"), an expansion of the St. Leon Wind Facility, located at St. Leon Manitoba. St. Leon LP also wholly owns St. Leon II Wind Energy GP Inc., a Manitoba corporation which owns the remaining 1% general partnership interest in St. Leon II LP.

APOT is the sole limited partner, holding a 99% limited partnership interest, in Red Lily Wind Power II Limited Partnership (" **Red Lily II LP**"), a Saskatchewan limited partnership. The general partner of Red Lily II LP is Red Lily Wind Power II GP Inc., a Saskatchewan corporation, which is also owned by APOT and owns the remaining 1% general partnership interest.

APOT has two ownership interests in Alberta. It is the beneficial owner of one hydroelectric facility in Alberta (the "**Dickson Dam Hydro Facility**"). APOT also owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass facility and APOT directly holds a 49.9995% limited partnership interest in Valley Power LP.

## APCH Group

APCH, a subsidiary of APCo, is an Ontario corporation which controls the entities that own the majority of APUC's hydroelectric generating facilities in Canada. APCH owns Algonquin Power (America) Inc., a Delaware corporation, which is the parent company of APCo's operations in the United States.

In Ontario, APCH directly owns the Hurdman hydroelectrical generating facility (the " **Hurdman Hydro Facility**"). In Québec, APCH directly owns the hydro facilities known as Hydro Snemo, St. Raphael, Belleterre, and St. Brigette, in addition to owning 100% of the beneficial interests in the Rawdon and St. Alban hydroelectrical facilities (the "**Rawdon Hydro Facility**" and "**St. Alban Hydro Facility**" respectively). APCH also holds a direct interest in Société Hydro-Donnacona, S.E.N.C. ("**Donnacona LP**"), the owner of the Donnacona hydroelectrical facility (the " **Donnacona Hydro Facility**") . Donnacona LP is a Québec general partnership, and is owned 99.99% by APCH and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APCH. APCH also owns a 99.99% interest in Société en Commandité Chute Ford, a Quebec limited partnership which owns the Glenford hydroelectric facility and APCH owns 100% of Glenford Minority Inc., an Ontario Corporation, which is the general partner, holding a 0.01% interest in Société en Commandité Chute Ford.

APCH owns a 99% interest in Algonquin Power (Morse) LP, an Ontario limited partnership, which owns the Morse Wind Facility in Saskatchewan (the "**Morse Wind Facility**"). AirSource Power Fund GP Inc., a Canada corporation wholly owned by APOT holds the remaining 1% general partnership interest. APCH also owns 1631667 Alberta ULC, an Alberta unlimited liability corporation.

APCH also owns Algonquin Power Corporation Inc. (" **APCI**"), an Ontario corporation. APCI owns a 99.9% general partnership interest in Algonquin Power (Long Sault) Partnership (the "**LS Partnership**"), an Ontario general partnership which is a 50% partner in the Long Sault Rapids hydroelectrical facility (the "**Long Sault Hydro Facility**") with the remaining 50% being held by non-Algonquin interests. APCH has an agreement in place which allows it to buy an ownership interest in the parties which own the remaining 50% of the Long Sault Hydro Facility. APCI is also the sole owner of Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation which is the other general partner, holding the remaining 0.1% general partnership interest, in the LS Partnership.

APCH also holds note receivables in Long Sault Hydro Facility, which effectively provides it with the right to 100% of the after tax cash flows of the facility up to the end of 2013, 65% from 2014 to 2027 and 58% thereafter.

APCH has formed two Canadian federal corporations, Blue Hills Wind Managing Partner Inc. and Blue Hills Wind Minority Partner Inc., which collectively own a Saskatchewan general partnership: Blue Hills Wind Energy Project Partnership. This partnership was set up to take ownership of the Saskatchewan wind project that was owned by Windlectric.

APCH also owns 100% of Algonquin Power Services Canada Inc., a Canadian federal corporation that provides purchasing services to the Corporation's Canadian entities.

### APFA Group

APFA, a Delaware corporation, is owned by Algonquin Power (America) Inc (" **APA**"), a Delaware corporation which owns 100% of APFA's common shares and by APA's parent APCH which owns 100% of APFA's Series A Preferred shares. APFA owns or holds interests in the hydroelectric, thermal cogeneration, solar and wind entities and facilities in the U.S.

APFA owns Algonquin Power Sanger LLC, ( **"Sanger LLC**") a California limited liability company, and Algonquin Power Windsor Locks LLC ("**Windsor LLC**", a Connecticut limited liability company. These entities respectively own the U.S. Sanger facility and the Windsor Locks Thermal facility. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA owns Algonquin Tinker Gen Co. ( **"Tinker Gen Co."**) and Algonquin Northern Maine Gen Co. ( **"Northern Maine Gen Co."**), both Wisconsin companies. Tinker Gen Co. is also registered in New Brunswick, and Northern Maine Gen Co. is also registered in Maine. Tinker Gen Co. operates the electrical generating and transmission assets in New Brunswick (the "**Tinker Hydro Facility**"), and Northern Maine Gen Co. is the owner of the Millinocket and Caribou storage dams and the Squa Pan hydroelectrical facility (the "Squa Pan Hydro Facility") . APFA is also the sole owner of Algonquin Energy Services Inc. ("**AES**"), a Delaware corporation that is also registered in Connecticut, District of Columbia, Maine, Maryland and Ohio. AES contractually provides the electrical energy requirements for commercial and industrial customers in northern Maine.

APFA owns 100% of the interests in Algonquin Power (Gearbox Holdings), LLC, a Delaware LLC, which owns a 99% equity interest in Wind Portfolio SponsorCo LLC ("**WP SponsorCo**"), a Delaware LLC; the remaining 1% interest is held by Algonquin Power Fund (America) Holdco Inc. ("**APFA Holdco**"), a Delaware corporation which is 100% owned by APFA. WP SponsorCo owns 100% of the Class B managing interests in Wind Portfolio Holdings, LLC ("**WP HoldCo**"), a Delaware LLC. Non-Algonquin partners, JPM Capital Corporation, Morgan Stanley Wind LLC, and Gear Wind LLC, collectively hold 100% of the non-managing Class A interest in WP HoldCo, which in turn owns Wind Energy Portfolio Holdings I, LLC ("**WE HoldCo**"), a Delaware LLC. WE HoldCo directly owns three entities which each own separate wind projects in the USA: Sandy Ridge Wind, LLC, a Delaware LLC, owns the Sandy Ridge wind energy facility (the "**Sandy Ridge Wind Facility**" in Pennsylvania; Minonk Wind, LLC, a Delaware LLC, owns the Minonk wind energy facility (the "**Minonk Wind Facility**") in Illinois and Senate Wind, LLC, a Delaware LLC, owns the Senate wind energy facility (the "**Senate Wind Facility**") in Texas.

APFA owns Shady Oaks Holdings, LLC, a Delaware LLC, which owns TianRun Shady Oaks, LLC, a Delaware LLC, which owns GSG6, LLC, a Delaware LLC, which owns the Shady Oaks wind facility (the "**Shady Oaks Wind Facility**") in Illinois.

APFA owns Algonquin Power (Odell Holdings) Inc., a Delaware corporation, which owns Odell SponsorCo, LLC (" **Odell SponsorCo**"), a Delaware LLC. Odell SponsorCo owns 100% of the Class B managing interests in Odell Holdings, LLC, a Delaware LLC. Third party partners, not affiliated with the Corporation, collectively hold 100% of the non-managing Class A (tax equity) interests in Odell Holdings, LLC. Odell Holdings, LLC owns Odell Wind Farm, LLC, a Minnesota LLC, which owns the Odell wind facility (the " **Odell Wind Facility**") near Windom, Minnesota.

APFA owns Algonquin Power (Deerfield Holdings) Inc., a Delaware corporation which owns a 50% the membership interest in Deerfield Wind SponsorCo, LLC ("**Deerfield SponsorCo**"), a Delaware LLC. The remaining 50% of Deerfield SponsorCo is owned by Deerfield Holdings I, LLC, a subsidiary of Renewable Energy Systems Americas Inc., a third party unaffiliated with the Corporation. Deerfield SponsorCo owns Deerfield Holdco, LLC, a Delaware LLC, which owns Deerfield Wind Energy, LLC, a Delaware LLC which owns Deerfield wind facility (the " **Deerfield Wind Facility**") in Michigan.

APFA owns GB Solar Holdings, LLC, a Delaware LLC, which owns Great Bay Solar I, LLC, a Maryland LLC. Great Bay Solar I, LLC owns and is developing a solar facility (the "**Great Bay Solar Project**") in Somerset County, Maryland.

APFA also owns Algonquin Power (Bakersfield Holdings) LLC, (" **AP Bakersfield**") a Delaware LLC. AP Bakersfield owns 100% of the Class B managing interests in Algonquin SKIC 20 Solar LLC ("**SKIC 20**") which owns a 20 MW solar facility (the " **Bakersfield I Solar Facility**") in California. A non-affiliated third party partner owns the Class A (tax equity) non-managing interests in SKIC 20.

APFA owns 100% of Algonquin SKIC 10 SponsorCo, LLC (" **SKIC 10 SponsorCo**"), a Delaware LLC. SKIC 10 SponsorCo owns 100% of the Class B managing interests in Algonquin SKIC 10 Holdings, LLC, ("**SKIC 10 Holdings**") a Delaware LLC. A non-affiliated third party partner owns the Class A (tax equity) non-managing interests in SKIC 10 Holdings. SKIC 10 Holdings owns 100% of Algonquin SKIC 10 Solar, LLC ("**SKIC 10**"), a Delaware LLC, which owns a 10 MW solar facility (the " **Bakersfield II Solar Facility**") adjacent to the Bakersfield I Solar Facility.

APFA is also the sole owner of Algonquin Power (Bakersfield Land Holdings) LLC, a Delaware LLC which holds the real property leased to SKIC 10 and SKIC 20.

APFA owns a 99% interest in Algonquin Power (Wind Developments) LLC, a Delaware limited liability company set up for future wind development purposes. APFA's wholly owned subsidiary, APFA Holdco owns the remaining 1% of the LLC.

APFA is also the sole owner of of Algonquin Power Services America LLC, a Delaware LLC that provides purchasing services to APCo entities operating in the U.S.

### (ii) Liberty Utilities Group

### Liberty Utilities Group's Electric, Natural Gas, Water, and Wastewater Utilities

Liberty Utilities owns Liberty Utilities (CalPeco Electric), LLC, a California limited liability company (" **CalPeco**"). CalPeco owns an electricity distribution utility in the Lake Tahoe basin and surrounding areas in California ("**CalPeco Electric System**").

CalPeco owns 100% of the Class B managing interests in Liberty Utilities (Luning Holdings) LLC (" **Luning Holdings**"), a Delaware LLC. The Class A non-managing interests in Luning Holdings are owned by Firstar Development, LLC, a non-APUC related entity. Luning Holdings owns 100% of Luning Energy LLC, a Delaware LLC which owns a 50 MW photovoltaic project in Nevada.

Liberty Utilities owns Liberty Utilities (Midstates Natural Gas) Corp. (" **Liberty Midstates**"), a Missouri corporation. Liberty Midstates owns natural gas distribution utility assets in Missouri, Iowa and Illinois (the "**Midstates Gas Systems**").

Liberty Utilities owns Liberty Energy Utilities (New Hampshire) Corp. (" **Liberty Energy (NH)**"), a Delaware corporation registered to do business in New Hampshire. Liberty Energy (NH) owns Liberty Utilities (Granite State Electric) Corp., which owns an electrical distribution utility in New Hampshire (the "**Granite State Electric System**") and Liberty Utilities (EnergyNorth Natural Gas) Corp., which owns a natural gas distribution utility in New Hampshire (the "**EnergyNorth Gas System**").

Liberty Utilities owns Liberty Utilities (Peach State Natural Gas) Corp., a Georgia corporation (" **Peach State**"). Peach State owns natural gas distribution utility assets in Georgia (the "**Peach State Gas System**").

Liberty Utilities owns Liberty Utilities (New England Natural Gas Company) Corp., a Delaware corporation registered to do business in Massachusetts, which owns natural gas distribution utility assets in Massachusetts (the "**New England Gas System**").

Liberty Utilities also owns Liberty Utilities Energy Solutions Corp. (" **Liberty Energy Solutions**"), a Kansas corporation, which in turn owns Liberty Utilities Energy Solutions (Appliance) Corp., a Massachusetts corporation which divested all its assets, namely a retail gas appliance business, in June of 2015. Liberty Energy Solutions also owns Liberty Utilities Energy Solutions (Solar) Corp., a Delaware corporation which owns Liberty Utilities Energy Solutions (Solar 1) Corp., also a Delaware corporation. Liberty Energy Solutions owns Liberty Utilities Energy Solutions (CNG) Corp. and Liberty Utilities Energy Solutions (LNG) Corp., both being Delaware corporations.

Liberty Utilities owns Western Water Holdings, LLC, a Delaware LLC, which owns Liberty Utilities (Park Water) Corp. (" **Park Water**"), which owns the Park Water System in Downey, California. Park Water also owns Mountain Water Company ("**Mountain Water**"), a Montana company which owns the Mountain Water Facility in Missoula, Montana, and Liberty Utilities (Apple Valley Ranchos Water) Corp. ("**Apple Valley**"), a California company which owns the Apple Valley Ranchos water facility ( the "**Apple Valley Ranchos Water System** ") in Apple Valley, California. These assets were acquired on January 11, 2016.

Liberty Utilities owns 100% of Liberty Utilities (Central) Co., a Delaware corporation, which owns 100% of The Empire District Electric Company ("**Empire**"), a Kansas corporation. Empire directly owns electric and water distribution utility assets serving locations in Missouri, Kansas, Oklahoma, and Arkansas. It also directly owns 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. Empire owns a 12% interest in the Iatan coal-fired power generation facility in Missouri, and a 7.5% interest in the Plum Point coal-fired power generation facility in Arkansas. Empire has a direct interest in PPAs for the Elk River and Cloud County wind facilities in Kansas. Empire also owns the Empire District Gas Company, which operates a natural gas distribution utility in locations in Missouri, and Empire District Industries, Inc. which owns a fiber optics business in Missouri. Empire also owns EDE Company Arkansas, LLC, an Arkansas LLC and EDE Property Transfer Corp., a Delaware corporation; both of which are currently inactive and have been set up for potential future activities.

Liberty Utilities also owns Liberty Utilities (Pine Bluff Water) Inc., which owns and operates the Pine Bluff water system (" **Pine Bluff Water System**"), located in Pine Bluff, Arkansas.

Liberty Utilities owns Liberty Utilities (White Hall Water) Corp. and Liberty Utilities (White Hall Sewer) Corp., both being Arkansas corporations, which respectively own the White Hall Water System and the White Hall Waste System in Arkansas.

Liberty Utilities also owns Liberty Utilities (Woodson-Hensley Water) Corp., an Arkansas corporation which owns and operates a water storage and distribution system to serve the communities of Woodson and Hensley in Arkansas.

Liberty Utilities owns Liberty Utilities (Pipeline & Transmission) Corp. which owns 50% of Northeast Energy Center, LLC, a Delaware corporation, which is developing a liquefied natural gas facility in Massachusetts. The remaining 50% is owned by RBS Energy, LLC, a non-APUC related entity.

### Liberty Utilities (Sub) Corp.

Liberty Utilities owns Liberty Utilities (Sub) Corp. ("Liberty SubCo"), a Delaware corporation. With the exception of Pine Bluff Water, Mountain Water, Apple Valley Ranchos Water System, the Park Water System, the White Hall Water and Waste System and the water distribution assets of Empire, Liberty SubCo is the parent company of the water and wastewater entities.

Liberty SubCo owns, through subsidiaries, the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois. Most of these 100% wholly-owned subsidiaries (except Liberty Utilities (Northwest Sewer) Corp. ), are currently conducting business as “Liberty Utilities”; however, the actual legal names of the relevant entities are set out below.

In Arizona, the following Arizona corporations own the following facilities: Liberty Utilities (Bella Vista Water) Corp. owns the Bella Vista Water System, the Northern Sunrise Water System, and the Southern Sunrise Water System; Liberty Utilities (Black Mountain Sewer) Corp. owns the Black Mountain Waste System; Liberty Utilities (Gold Canyon Sewer) Corp. owns the Gold Canyon Waste System; Liberty Utilities (Litchfield Park Water & Sewer) Corp. owns the Litchfield Waste & Water Systems; Liberty Utilities (Rio Rico Water & Sewer) Corp. owns the Rio Rico Water & Waste Systems; and Liberty Utilities (Entrada Del Oro Sewer) Corp. owns the Entrada Del Oro Waste System.

In Texas, the following Texas corporations own the following facilities: Liberty Utilities (Tall Timbers Sewer) Corp. owns the Tall Timbers Waste System; Liberty Utilities (Woodmark Sewer) Corp. owns the Woodmark Waste System; Liberty Utilities (Silverleaf Water), LLC, a Texas limited liability company, owns water and wastewater treatment assets at the Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as “Big Eddy”) Resorts; and Liberty Utilities (Seaside Water), LLC., a Texas limited liability company, owns water and wastewater treatment assets at the Seaside Resort.

In Missouri, Liberty Utilities (Missouri Water), LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain, Timbercreek resorts, the water utility in Noel, Missouri and a utility in eastern Missouri. In Illinois, Liberty Utilities (Fox River Water), LLC, an Illinois limited liability company, owns assets serving the Fox River Resort.

### LU Canada

LU Canada owns Algonquin Power (Ontario Transmission) Inc., an Ontario corporation, which owns 50% of Sagatay Holdings Partnership, an Ontario general partnership. The remaining 50% is owned by Morgan Geare Inc., a non-APUC related entity. Sagatay Holdings Partnership owns 49.99% of Sagatay Transmission Limited Partnership, (“Sagatay LP”) an Ontario limited partnership. Sagatay LP is also owned 25% by the Mishkeegogamang First Nation and 25% by the Ojibway Nation of Saugeen First Nation, both of which are non-Algonquin entities. LU Canada also owns Liberty Utilities (Sagatay Transmission) GP Inc., an Ontario corporation, which owns the remaining 0.01% of Sagatay LP and acts as its general partner.

#### (iii) Other

Outside of APCo, LU Canada and their respective subsidiary entities, as described above, APUC directly owns Warwick (Canada) Corp., an Ontario corporation and 3793257 Canada Inc. (“**3793257**”), a holding company incorporated under the Canada Business Corporation Act.

APUC also has ownership interests in a group of special purpose financing entities, including 90% of Liberty Utilities Finance GP 1 (“ **LU GP1**”), a Delaware general partnership. LU GP1 owns 99.9% of Liberty Utilities Finance GP 2 (“**LU GP2**”), a Delaware general partnership. The minority partner of both LU GP1 and LU GP2 is 3793257. LU GP2 owns Liberty Utilities Finance (Canada) ULC, an Alberta unlimited liability corporation which in turn owns Liberty Utilities Finance (US) LLC, a Delaware limited liability company. The above entities were formed as special purpose financing entities used in Liberty Utilities financings.

LU Canada controls a limited partnership formed for purposes of holding the corporate head office location. LU Canada owns 99.99% of Davis Road LP, an Ontario limited partnership, and it also owns 100% of Davis Road GP Inc., the general partner and 0.01% owner of Davis Road LP.

### 1.2.2 Other Interests in Energy Related Developments

The Corporation also has certain notes receivable and non-controlling equity interests in companies owning generating facilities as described below. APT owns 25% of the Class B non-voting shares issued by Cochrane Power Corporation, the owner of a combined cycle cogeneration facility located in Cochrane, Ontario. APT also owns 32.4% of the Class B non-voting shares in Kirkland Lake Power Corporation, an entity which burns natural gas and wood waste to generate electricity. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais Energie, Société en Commandite.

In addition, APCo is entitled to a royalty in the form of cash flows generated by the Long Sault Hydro Facility. It is also the owner of a 14.14% secured, subordinated note in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc.

APUC also owns the Class B limited partnership units of St. Leon LP, the legal owner of the St. Leon Wind Facility.

# 2. GENERAL DEVELOPMENT OF THE BUSINESS

## 2.1 General

### 2.1.1 Business Strategy

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

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

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

**Renewable Generation Group**

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

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

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

**Liberty Utilities Group**

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

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

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

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

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

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

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

## 2.2 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.

### 2.2.1 Fiscal 2014

#### Corporate

**(i) Dividend Increased to U.S. $0.35 Per Common Share Annually**

On August 14, 2014, the Board approved a dividend increase to U.S. $0.35 per share per annum, paid quarterly at a rate of U.S. $0.0875 per share, a 12.4% increase over the previous dividend of Cdn $0.34 calculated using the exchange rate in effect at that time. The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. In 2014, APUC's consolidated assets were approximately 80% based in the U.S. and generated approximately 77% of its underlying cash flows.

**(ii) Issuance of $100 million Preferred Shares**

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D (the " **Series D Shares**") at a price of $25 per share, for aggregate gross proceeds of $100.0 million. The Series D Shares yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS, respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

**(iii) Issuance of Common Shares**

On September 16, 2014, APUC completed a public offering (the " **September 2014 Offering**") of 16,860,000 Common Shares at a price of $8.90 per share, for gross proceeds of approximately $150.0 million. On September 26, 2014, the underwriters exercised the over-allotment option granted with the September 2014 Offering and an additional 2,529,000 Common Shares were issued on the same terms and conditions of the September 2014 Offering. As a result, APUC issued an aggregate of 19,389,000 Common Shares under the September 2014 Offering for the total gross proceeds of approximately $172.6 million.

On December 11, 2014, APUC completed a public offering of 10,055,000 Common Shares at a price of $9.95 per share, for gross proceeds of approximately $100.0 million.

Net proceeds of both Common Share offerings were used to finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

**(iv) Private Placement of Subscription Receipts to Emera Inc.**

On September 4, 2014, APUC and Emera Inc. (" **Emera**") entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,865,170 Subscription Receipts of APUC at a price of $8.90 per subscription receipt, for an aggregate subscription amount of $70.0 million.

On September 26, 2014, as a result of the underwriters exercising their over-allotment option with respect to the September 2014 Offering, an additional 843,000 subscription receipts were issued to Emera at a price of $8.90 per subscription receipt, for an aggregate subscription amount of $77.5 million.

On December 2, 2014, APUC and Emera entered into an additional subscription agreement to which Emera agreed to subscribe for an aggregate of 3,316,583 subscription receipts at a price of $9.95 per subscription receipt, for an aggregate subscription amount of $33.0 million.

The proceeds of the subscription receipts private placements were intended to be used to partially finance the acquisitions of the Odell Wind Project and Park Water System.

## Renewable Generation Group

### (i) Acquisition of Odell Wind Project

On November 14, 2014, the Renewable Generation Group acquired an interest in a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota (the "**Odell Wind Project**"). The Odell Wind Project is situated on approximately 23,000 acres of leased land and utilizes 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year power purchase agreement ("PPA"), all energy, capacity and Renewable Energy Credits ("**RECs**") from the project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the midwest U.S. Construction of the project began in the second quarter of 2015, and construction financing including a portion that bridges to tax equity's investments was arranged by the project company during 2015.

The Renewable Generation Group's participation in the project during the construction phase was structured as a 50% equity interest in a new joint venture with a third party developer. On July 29, 2016, the Odell Wind Facility achieved commercial operation ("**COD**"). On September 15, 2016, the Corporation acquired the remaining 50% interest in Odell SponsorCo LLC for U.S. $26.5 million and now controls the project.

### (ii) Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Renewable Generation Group completed the construction of its 10 MW solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014. The facility represents the first solar project in the Renewable Generation Group's portfolio. The facility is expected to generate approximately 14,400 MW-hrs of electricity annually with the power sold under a 20 year feed in tariff ("**FIT**") contract with the Independent Electricity System Operator (" **IESO**"), formerly the Ontario Power Authority (" **OPA**").

### (iii) Completion of St. Damase Wind Project

On December 2, 2014, the first phase of the wind facility located in the local municipality of Saint-Damase (the " **Saint-Damase Wind Project**") reached commercial operations. The 24 MW facility is expected to generate 76,900 MW-hrs of electricity annually with the power sold under a 20 year PPA with Hydro-Québec Distribution ("**Hydro-Québec**").

The turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Project qualify as Canadian Renewable and Conservation Expense, and therefore a significant portion of the Phase I capital cost was eligible for a refundable Quebec tax credit with a value of $14.3 million. Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting, and entering into appropriate energy sales arrangements.

### (iv) Expansion of Bakersfield I Solar Project

On November 24, 2014, APUC announced that it intended to proceed with the 10 MW Bakersfield II Solar Project on 64 acres of land adjacent to its 20MW Bakersfield I Solar Project in Kern County, California.

The 10MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility.

### (v) Acquisition of the Remaining 40% of a 400 MW Wind Power Portfolio

On March 31, 2014, the Renewable Generation Group acquired from Gamesa Wind US, LLC (" **Gamesa**") the remaining 40% of the Class B partnership units of the entity which owns a three facility 400 MW wind portfolio in the United States (the "**U.S. Wind Portfolio**") for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Renewable Generation Group now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts. The acquisition was funded primarily from the proceeds from the $200.0 million of debentures issued by the Renewable Generation Group early in 2014 as discussed below.

### (vi) $200 million Senior Unsecured Debentures

On January 17, 2014, the Renewable Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "**2014 Renewable Generation Group Debentures**") pursuant to a private placement in Canada and the United States. The 2014 Renewable Generation Group Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, the Renewable Generation Group entered into a fixed for fixed cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

Net proceeds were used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under its bank credit facility, and for general corporate purposes.

**(vii) Additional Liquidity**

On July 31, 2014, the Renewable Generation Group increased the credit available under the Renewable Generation Group credit facility to $350.0 million from $200.0 million to provide additional liquidity in support of the group's development portfolio. In addition to the larger size, the maturity of the facility was extended from three to four years and now extends until July 31, 2018.

## Liberty Utilities Group

**(i) Agreement to acquire Park Water**

On September 19, 2014, the Liberty Utilities Group announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure to acquire the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. (“**Park Water**”). The Park Water acquisition closed on January 8, 2016.

Please see "2.2.3 Fiscal 2016 Liberty Utilities Group Highlights" for additional description of the Park Water acquisition.

**(ii) Acquisition of White Hall Water System**

On May 30, 2014, the Liberty Utilities Group acquired the assets of the White Hall water and waste system (the " **White Hall Water System**" and "**White Hall Waste System**", respectively) and together the "**White Hall Water and Waste System**") , a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water and Waste System serves approximately 1,900 water distribution and 1,900 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, was approximately U.S. $4.5 million.

**(iii) Successful Completion of the Granite State Electric System Rate Case**

In the first quarter of 2013, the Granite State Electric System filed a rate case with the New Hampshire Public Utilities Commission (" **NHPUC**") seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the NHPUC approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014.

**(iv) Successful Completion of the Peach State Gas System GRAM Filings**

On October 1, 2013, the Peach State Gas System filed an application for an increase in revenue of U.S. $4.9 million in its annual Georgia Rate Adjustment Mechanism ("**GRAM**") filing with the Georgia Public Service Commission (" **GPSC**"). In January 2014, the Liberty Utilities Group and the staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $3.2 million, and the recovery of U.S. $1.7 million of carrying charges on deferred rate base in a future GRAM filing. Commission approval was received in May 2014, with new rates effective as of June 1, 2014.

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.7 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015 for the period February 1, 2015, through January 31, 2016 were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). GPSC approval was received on December 4, 2014.

**(v) Successful Completion of the LPSCo Water System Rate Case**

On February 28, 2013, the LPSCo Water distribution and wastewater treatment facility (the " **LPSCO System**") filed a general rate case with the Arizona Corporation Commission ("**ACC**") related to the LPSCo System sought, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In April 2014 the commission approved a $1.8 million increase in rates effective on May 1, 2014.

**(vi) Successful Completion of the Midstates Gas System Rate Case**

On February 6, 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission (" **MPSC**") seeking an increase in revenue of U.S. $7.6 million, consisting of U.S. $6.3 million in new, incremental revenue and U.S. $1.3 million through the infrastructure system replacement surcharge ("**ISRS**") . The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case has concluded and an Order was issued by the MSPC on December 3, 2014, approving a U.S. $4.9 million revenue increase effective January 2, 2015.

**(vii) Pine Bluff Water System Rate Case Proceedings**

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

**(viii) EnergyNorth Gas System Rate Case Proceedings**

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

### 2.2.2 Fiscal 2015

#### Corporate

**(i) Dividend Increased in second quarter 2015 to U.S. $0.385 Per Common Share Annually**

On May 7, 2015, the Board approved a dividend increase of U.S. $0.035 annually bringing the total annual dividend to U.S. $0.385 per common share, paid quarterly at the rate of U.S. $0.0963 per common share, an increase of 10% over the previous dividend rate.

**(ii) $150 Million Bought Deal Offering of Common Shares**

On December 2, 2015 APUC issued on a bought deal basis (the " **December 2015 Offering**") 14,355,000 Common Shares at a price of $10.45 per share for gross proceeds of approximately $150.0 million.

Net proceeds of the December 2015 Offering were used to partially fund APUC's capital growth program, to reduce short-term debt and for general corporate purposes.

#### Renewable Generation Group

**(i) Deerfield Wind Project Joint Venture**

On October 19, 2015, the Renewable Generation Group announced it had agreed to jointly develop the 150 MW Deerfield Wind Project in the United States with RES.

The Deerfield Wind Project is located in central Michigan and is situated on approximately 20,000 acres of leased land. The project utilizes 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. The project has a 20 year PPA with a local electric distribution utility serving approximately 260,000 customers in Michigan.

The total project cost is expected to be approximately U.S. $303.0 million. The project achieved commercial operations on February 21, 2017.

**(ii) Great Bay Solar Project**

On December 1, 2015, the Renewable Generation Group announced the development of a new 75 MW contracted solar generation facility, located in Somerset County Maryland ("**Great Bay Solar Project**"). The U.S. $180.0 million facility is expected to achieve commercial operations expected by the end of 2017. The facility is contracted under a 10 year PPA and expected to generate 152 GW-hrs annually. The facility will also generate Solar Renewable Energy Credits (SRECs) which will be sold into the Maryland market.

**(iii) Completion of Morse Wind Facility**

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

#### (iv) Completion of Bakersfield I Solar Project

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

Consistent with the commitment to expand its solar generation portfolio, the Renewable Generation Group announced that it was pursuing the construction of the 10 MW Bakersfield II Solar Facility immediately adjacent to the Bakersfield I Solar Facility. The Bakersfield II Solar Facility achieved commercial operations on January 11, 2017.

#### (v) Letter of Credit Facility

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

### Liberty Utilities Group

#### (i) Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return on the rate base at its various utility systems. During 2015, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annual revenue increase of approximately U.S. $18.1 million with the full annualized impact of these rate cases to be realized in 2016.

#### (ii) U.S. Debt Private Placement

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

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

#### (iii) Acquisition of New Hampshire Gas

On January 2, 2015, the EnergyNorth Gas System completed the acquisition of the New Hampshire Gas Corporation (the "New Hampshire Gas System"), a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System serves approximately 1,200 propane gas distribution customers. The total purchase price for the New Hampshire Gas System was approximately U.S. $3.16 million, subject to certain closing adjustments.

## 2.2.3 Fiscal 2016

### Corporate

#### (i) Dividend Increased in Second Quarter 2016 to U.S. $0.4236 Per Common Share Annually

On May 12, 2016, the Board approved a dividend increase of U.S. $0.0384 per common share annually, bringing the total annual dividend to U.S. $0.4236 per common share, an increase of 10% over the previous dividend rate. The dividend increase reflected successful growth initiatives, including completion of the acquisition of Park Water, the announcement of the Corporation’s agreement to acquire Empire, and continued construction and development of new power generation facilities.

#### (ii) Dual Listing of Algonquin Common Shares on the New York Stock Exchange

During the fourth quarter APUC received approval to list its commons shares for trading on the New York Stock Exchange (" **NYSE**") under the ticker symbol "AQN". The Corporation has been a U.S. Securities and Exchange Commission (“**SEC**”) registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the Toronto Stock Exchange ("**TSX**") also under the ticker symbol "AQN".

#### (iii) U.S. $235 Million Corporate Term Credit Facility

On January 4, 2016, the Corporation entered into a U.S. $235.0 million term credit facility (" **Corporate Term Facility**") with two U.S. banks. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2018.

## Renewable Generation Group

### (i) Acquisition of 75% interest in the Red Lily I Partnership

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

### (ii) Completion of the Odell Wind Project

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

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

### (iii) Purchase of Turbines to Safe Harbour Production Tax Credit Rate

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

## Liberty Utilities Group

### (i) Acquisition of the Park Water System

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

Total consideration for the utility purchase was U.S. $341.3 million, which includes the assumption of approximately U.S. $91.8 million of existing debt. This acquisition maintains APUC's strategic business mix and further enhanced its investment grade consolidated capital structure.

The water utility located in western Montana is currently the subject of a condemnation lawsuit filed by the city of Missoula. Please see "*4.2.2 Operational Risk - Regulatory Risk - Condemnation Expropriation Proceedings*" and "*9.2 Regulatory Actions*" for a detailed description and discussion of the condemnation proceedings.

### (ii) Successful Rate Case Outcomes

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

### (iii) Completion of Phase I of the North Lake Tahoe Transmission System Upgrades

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

## 2.3 Recent Developments - 2017

### Corporate

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

On January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of Empire for an aggregate purchase price of approximately U.S. $2.4 billion including the assumption of approximately U.S. $0.9 billion of debt.

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

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

APUC expects that the Empire Acquisition will be accretive to earnings per common share in the first full year following closing and approximately 7% - 9% accretive to APUC's net earnings per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. APUC also expects that the Empire Acquisition will be approximately 12% - 14% accretive to Adjusted Funds From Operations per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. The increased contribution from regulated operations is also expected to further enhance the stability and predictability of Adjusted EBITDA, net earnings and quality of cash flows.

APUC has filed Form 51-102F4 dated March 10, 2017 in respect of the Empire Acquisition which may be found on SEDAR at www.sedar.com.

**(ii) Annual Dividend Increased from U.S. $0.4235 to U.S. $0.4659 and**

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

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

In addition the completion of the Empire Acquisition in the first quarter of 2017, APUC has completed construction of new electric generating stations and has a number of electric generating stations in construction and under development. Collectively these growth initiatives have continued to raise the growth profile of the Company. As a result, on January 16, 2017, the Board approved a dividend increase of U.S. $0.0424 per common share annually, bringing the total annual dividend to U.S. $0.4659 per common share, an increase of 10% over the previous annual dividend rate.

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

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

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

**Strong Year of operating results**

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

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

**(iii) Completion of Financing Related to the Empire Acquisition**

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

In the first quarter of 2016, in connection with the Acquisition, APUC and its direct wholly-owned subsidiary, LU Canada, entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

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

*U.S. $750 Million Private Placement Offering*

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

### Renewable Generation Group

**(i) Completion of the Deerfield Wind Project**

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

**(ii) Completion of the Bakersfield II Solar Project**

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

**(iii) Issuance of $300 million Senior Unsecured Debentures**

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

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

### Liberty Utilities Group

**(i) Completion of the Luning Solar Project.**

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

# 3. DESCRIPTION OF THE BUSINESS

## 3.1 Renewable Generation Group

### 3.1.1 **Regulatory Regimes - Power Generation**

#### (i) Canada

The electricity supplied within the Canadian provinces is primarily generated by government-owned corporations, such as Ontario Power Generation Inc. and Hydro-Québec. Independent power producers, such as APUC provide additional capacity and supply to the grids. In Canada, the provinces have legislative authority over the generation, transmission and distribution of electricity. This in turn means that each province may have different requirements for the business to comply with in respect of the projects it owns in each province.

Generally speaking, each province in which the Corporation operates has various pieces of legislation in effect with which the business must comply. These relate to the generation, transmission and distribution of electricity in the province, the administration of the electric system, as well as the creation and authority of various governmental agencies who have oversight of an aspect of the industry, such as the independent system operator (the "ISO") and the provincial energy board, utilities commission or other similar authority responsible for rate-making and regulatory oversight of the industry. In addition, some provinces require a generator of electricity to be licensed and registered with the appropriate governmental authority and the Corporation must comply with the conditions of license or registration accordingly. In addition to the legal requirements, the system operators have promulgated market rules to be complied with within their operating jurisdictions and any codes, rules and standards of the applicable energy board or utilities commission must be complied with.

#### (ii) United States

The power generation industry in the United States is regulated by the FERC under the U.S. Federal Power Act (" **FPA**"), the 2005 Energy Policy Act, the Public Utilities Regulatory Policies Act (**PURPA**) and the Public Utility Holding Company Act of 2005 (" **PUHCA**").

(1) Rate Regulation

All of the Renewable Generation Group's operating U.S. power generation facilities are either: (1) exempt wholesale generators (" **EWGs**"); or (2) qualifying small power or cogeneration facilities ("**QFs**"). EWGs sell electricity exclusively in wholesale markets, while QFs with a power production capacity of 20 MW or less are exempt from most regulation under the FPA. There are two types of QFs: (1) qualifying small power production facilities; and (2) qualifying cogeneration facilities. In order to be a qualifying small power production facility, which includes hydro, geothermal, solar and biomass, the facility must meet the maximum size and fuel use criteria specified in FERC's regulations. In order to be a qualifying cogeneration facility, the facility must meet the operating and efficiency criteria specified in FERC's regulations. All of the Renewable Generation Group's operating U.S. power generation facilities that are EWGs possess FERC authorization to engage for sales for resale at market-based rates ("**MBR Authority**"). The QF with a capacity greater than 20 MW also possesses MBR Authority. QFs with a capacity of 20 MW or less are not required to possess MBR Authority for their power sales, unless within a certain geographic proximity of one another. MBR Authority is available to EWGs and certain QFs and is obtained by showing that the generator and its affiliates do not possess vertical or horizontal market power in the relevant market. Once MBR Authority is obtained, the EWG or QF with a capacity greater than 20 MW, may sell its power into the relevant market at market-based rates. Each entity with MBR Authority must detail its sales into the market by filing quarterly reports which details the relevant contracts used to sell power and the rates obtained for such power sales. QFs with a capacity of 20 MW or less are not required to file quarterly reports.

(2) NERC

The 2005 Energy Policy Act expanded FERC's authority to impose mandatory reliability standards on the bulk electric system and to impose penalties on entities that manipulate the electric and natural gas markets. On June 20, 2006, the North American Electric Reliability Corporation (NERC) was certified by FERC as the Electric Reliability Organization (ERO) for North America. NERC's mission is to ensure the reliability and security of the North American Bulk Electric System. NERC accomplishes its mission through enforcement of mandatory regulation of reliability operating standards. NERC also annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is subject to oversight by FERC and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people. Some assets of the Renewable Generation Group and the Liberty Utilities Group are subject to regulation by NERC.

(3) PUHCA

APUC is also subject to the PUHCA. PUHCA and FERC's implementing regulations impose certain books, records and accounting requirements on public utility holding companies. APUC is a public utility holding company and subject to such regulations. The Renewable Generation Group's intermediate holding companies claims exemption from PUCHA under Title 18, Part 366.3 of the U.S. Code of Federal Regulations (CFR), which provides that a company that is a holding company solely by virtue of holding interests in QFs, EWGs and foreign utility companies is exempt from the books, records and accounting provisions of PUHCA and FERC's regulations. Should any of the EWGs or QFs cease qualifying for such status by no longer meeting the regulatory requirements for qualification, then the exemption would no longer apply. At that time, the books, records and accounting requirements, requiring use of the Uniform System of Accounts would then apply.

### 3.1.2 Description of Operations

**Hydroelectric Generating Facilities**

#### (i) Production Method

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as "**head**"), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a head pond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. 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 APUC operates in Canada are Alberta, Ontario, New Brunswick and Québec. In the US, 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. A summary of the PPAs for the Renewable Generation Group's Renewable Energy Division is set out in Schedule A.

(1) Alberta

The electrical power industry in Alberta is regulated by the Electric Utilities Act (Alberta) ("EUA"). The Power Pool of Alberta ("Alberta Power Pool") was established under the EUA to provide a competitive, real-time spot market for electric energy. The Alberta Power Pool is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the Alberta Power Pool.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the Ontario Energy Board (the " **OEB**"). While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

The Ontario Electricity Financial Corporation ("OEFC") purchases the energy generated by the Ontario facilities and holds all rights, obligations and liabilities under the existing contracts. APUC's relevant subsidiary entities have also received a license to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick and Northern Maine

Effective October 1, 2013, the New Brunswick government amended the provincial Electricity Act (New Brunswick), which resulted in the re-amalgamation of the New Brunswick System Operator ("**NBSO**") with members of the New Brunswick Power Corporation (" **NB Power**"), a vertically-integrated group of companies, resulting in the transmission system operation functions of the NBSO being performed by NB Power's Transmission and System Operator division.

(4) Québec

Hydro-Québec is the primary electricity generator, transmitter, and distributor of electricity in the province of Québec; its sole shareholder is the Québec government. It uses mainly renewable generating options, in particular large hydro, and supports

the development of other technologies, such as wind energy and biomass. It also sells power on wholesale markets in northeastern North America.

#### (iii) Material Facilities

(1) Long Sault Hydro Facility

The **Long Sault Hydro Facility** is a run-of-river 18 MW hydroelectric generating facility consisting of four 4,500 kilowatt pit turbine generating units located on the Abitibi River, 19 kilometres north of the Town of Cochrane, in northern Ontario.

The Long Sault Hydro Facility was commissioned in 1998.

The facility was developed by a joint venture between wholly-owned subsidiaries of APUC and N-R Power Partnership, an unrelated third party (the "**Co-Owners**"). There is a non-recourse loan outstanding which is secured against the facility and the Co-Owners' interests therein.

The Long Sault Hydro Facility has entered into a 50 year PPA with OEFC effective April 1, 1998 under which all electricity produced at the facility is sold to the OEFC. The PPA may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to the greater of OEFC's total market cost.

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge which commenced in January 2008.

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner's interest for 90% of the fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the facility on their behalf for nominal consideration.

There is an outstanding senior loan against the facility in the amount of $33.5 million as at December 31, 2016. The loan matures in January 2028 and bears interest at an interest rate of 10.21% compounded annually for the balance of the loan. Blended payments of principal and interest are made monthly. The loan is non-recourse and is secured by the facility and the ownership interests therein.

(2) Côte Ste-Catherine Hydro Facility

The Côte Ste-Catherine Hydro Facility is a hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The facility has a total installed capacity of 11.1 MW. The facility is owned by the Mont-Laurier Partnership.

The land and water rights necessary for the operation of the facility have been obtained by way of a lease agreement with the St. Lawrence Seaway Authority. Although the facility is located on a federal waterway, the Province of Quebec has asserted jurisdiction over the water rights to this facility and has also asserted a claim against a predecessor by amalgamation to APCH for payment of revenues paid to the federal authority.See section 9.1, "Legal Proceedings.

The Côte Ste. Catherine Hydro Facility has a PPA with Hydro-Québec under which all power generated by the facilities is sold to Hydro-Québec. The standard Hydro-Québec PPA stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec PPAs, if a facility produces less energy than the minimum, a penalty is payable to Hydro-Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

APUC is currently in negotiations with Hydro-Québec to renegotiate pricing for the extension period of the PPAs related to a number of other Québec-based hydro sites.

(3) Tinker Hydro Facility

The Tinker Hydro Facility is located 5 miles north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The facility consists of five hydro units and a 1 MW diesel generator; the total nameplate capacity of the station equals approximately 34.5 MW.

The Tinker Hydro Facility was acquired by APUC on January 13, 2010.

As part of the generation assets in New Brunswick and Northern Maine, APUC owns an electrical transmission system consisting of 14.7 kilometres of 69 kV transmission line facilities. These facilities are 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. As part of the recent filings under the *Electricity Act* (New Brunswick), Tinker Gen Co. sought two initiatives under Matter 256; to secure pre-authorization of a transformer upgrade and to establish an updated revenue requirement for the transmission service function. On March 24, 2016, the New Brunswick

Energy and Utilities Board (the "**NBEUB**") issued an order in Matter 256 authorizing an increase in the Tinker Hydro Facility annual revenue requirement to $0.9 million. This approval does not contain any additional revenue requirement for the transformer upgrade authorized in the EUBNB's September 2015 order. Since the third quarter of 2016, the Tinker Hydro Facility has been installing the authorized transformer upgrades following the receipt of all necessary permits issued. Tie-ins are being coordinated with affected stakeholders in New Brunswick. Following the start of service, the Tinker Hydro Facility will submit a request to increase its revenue requirement for the additional $12.0 million of capital investment.

The output of the Tinker Hydro Facility is actively marketed along with certain other owned assets of the Corporation which sell the energy they generate together with any applicable environmental attributes less any associated transportation costs. The Corporation provides energy to commercial and industrial customers in the Northern Maine markets primarily by selling energy from the Tinker Hydro Facility

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, and from time to time it sells any excess generation to the market. Risk associated with energy sold in excess of what is generated by the Tinker Hydro Facility is managed through the purchase of fixed volume/prices from the market. In addition, APUC negotiates appropriate pricing with large retail and wholesale consumers in Northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

(4) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Dickson Dam Hydro Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River.

The Dickson Dam Hydro Facility was commissioned on January 16, 1992.

APUC sells all of the power generated at the Dickson Dam Hydro Facility in the Alberta Power Pool at market rates.

The Dickson Dam Hydro Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available water flows for generating power until March 31, 2030. The Use of Works Agreement provides certain rights in favour of the Minister of Environment (Alberta) in connection with the Minister's water management objectives.

### 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 APUC's operational wind facilities in Canada are Manitoba for the St. Leon Wind Facilities, Saskatchewan for the Red Lily I and Morse Wind Facilities, and Quebec for the Saint-Damase Wind Project. The electricity generated by the wind turbines is transmitted via electrical collection lines to the facility substations for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**") in the case of the St. Leon Wind Facilities, Saskatchewan Power Corporation (" **SaskPower**") in the case of the Red Lily I and Morse Wind Facility, and Hydro Quebec in the case of the Saint-Damase Wind Project. The purchaser then distributes the electricity to its customers or to other endpoints via the grid. The principal markets for APUC's wind facilities in the United States are the PJM Interconnection LLC ("**PJM**"), Midcontinent Independent System Operator, Inc. ("**MISO**") and Electric Reliability Council of Texas (" **ERCOT**") regional markets.

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through the Crown

Investments Corporation. SaskPower has set a target of 50% of generation capacity from renewables by 2030. As a result, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(3) Quebec

Hydro-Québec's hydroelectric portfolio accounts for 99% of electricity mix, and as such, the utility has encouraged the development of wind projects in the province in recent years. Hydro-Québec's previous wind project calls for tenders have resulted in over 3,000 MW of wind capacity to be installed in the province. In addition, another 275 MW of wind are under construction and another almost 400 MW are planned.

(4) Illinois and Pennsylvania

PJM is one of ten regional transmission organizations (" **RTOs**") operating in North America. PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high voltage electricity grid to ensure reliability for more than 60 million people.

(5) Michigan and Minnesota

The Midcontinent Independent System Operator ("**MISO**") is an **ISO**, similar to an RTO, operating in fifteen U.S. states and the Canadian province of Manitoba. MISO assures consumers of unbiased regional grid management and open access to the transmission facilities through their functional supervision. MISO has interconnections with PJM, ERCOT, and other RTOs and ISOs. The fifteen states where MISO operates are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, South Dakota, North Dakota, Texas and Wisconsin.

(6) Texas

ERCOT, like PJM, is one of the ten RTOs operating in North America. ERCOT is the successor to the Texas Interconnect System and its region occupies the entire Texas interconnection which occupies nearly all of the state of Texas. Unlike the other major North American Electric Reliability Corporation ("**NERC**") interconnections, the high voltage transmission and energy market within the Texas interconnection is operated by ERCOT as essentially a single power system instead of as a network of cooperating utility companies. The portion of the electric grid in the State of Texas that is under the administration of ERCOT was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation. ERCOT is a membership-based, non-profit council that provides electric power to approximately 23 million people in Texas.

### (iii) Material Facilities

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 104 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The St. Leon Wind Facility achieved commercial operation on April 1, 2006 and 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 5 years.

(2) St. Leon II Wind Facility

The St. Leon II Wind Facility is a 16.5 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg, adjacent to the St. Leon Wind Facility. The St. Leon II Wind Facility achieved commercial operations on March 1, 2012 and entered into a 25 year PPA with Manitoba Hydro effective July 1, 2012 under which all electricity produced is sold to Manitoba Hydro.

(3) Red Lily I Wind Facility

The Red Lily Wind Facility is a 26.4 MW wind energy facility located 5 km west of Moosomin, Saskatchewan. The Red Lily Wind Facility achieved commercial operation on February 28, 2011 and has a PPA with SaskPower with a term of 25 years from commencement of commercial operation and includes a 2% annual increase throughout the term of the agreement.

All of the equity in the Red Lily Wind Facility was initially owned by an independent investor, Concord Pacific Group. APUC's investment in the Red Lily Wind Facility was initially in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Red Lily Partnership. In addition to the loans extended by APUC, an additional $31.0 million of senior debt has been provided by a third party lender.

On February 23, 2016, a second tranche of subordinated loan for an amount equal to $15.6 million was advanced by APUC. The proceeds from this additional subordinated debt were used by the Red Lily Wind Facility to repay Tranche 2 of the Red Lily Partnership's senior debt, including the Corporation's portion. On March 1, 2016, the Corporation exercised its option to

formally exchange its debt investment and fee interest in the project for a 75% equity interest. The Concord Pacific Group retains a 25% ownership interest in the project. The earnings of the Red Lily Wind Facility are not consolidated into the financial statements of the Corporation and are instead accounted for using the equity method.

(4) Morse Wind Facility

The Morse Wind Facility is a 23 MW wind energy facility located near Morse, Saskatchewan, approximately 180 km west of Regina. The facility achieved commercial operation on April 22, 2015. The Morse Wind Facility has a PPA with SaskPower under the Green Options Partner Program with a term of 20 years.

(5) Saint-Damase Wind Project

The Saint-Damase Wind Facility is a 24 MW wind energy facility located in the MRC of La Matapédia in the Gaspé Region of the Province of Québec, 440 km east northeast of Québec City, Québec. The facility was developed in partnership with the Municipality of Saint-Damase. The Saint-Damase Wind Facility achieved commercial operations on December 2, 2014 and has entered into a 20 year PPA with Hydro-Québec beginning on this date.

(6) Shady Oaks Wind Facility

The Shady Oaks Wind Facility is a 109.5 MW wind energy facility located in Lee County, Illinois, 80 km west of Chicago. The Shady Oaks Wind Facility was acquired by the Corporation on January 1, 2013. The facility reached commercial operation in June 2012.

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.

(7) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind energy facility located near Tyrone, Pennsylvania, 180 km east of Pittsburgh. APUC first acquired an indirect interest in the Sandy Ridge Wind Facility on July 1, 2012. The Sandy Ridge Wind Facility reached commercial operation in February, 2012.

Sandy Ridge Wind, LLC is party to a long term energy production hedge (" **Primary Energy Production Hedge**") 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. 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.

(8) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind energy facility located near Minonk, IL, 200 km southwest of Chicago, IL. APUC first acquired an indirect interest in the Minonk Wind Facility on December 10, 2012. The Minonk Wind Facility reached commercial operation in December 2012.

Minonk Wind, LLC is party to the Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013. 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 energy market in which the Minonk Wind Facility is registered.

(9) Senate Wind Facility

The Senate Wind Facility is a 150 MW wind energy facility located near Graham, Texas, 200 km west of Dallas, Texas. APUC first acquired an indirect interest in the Senate Wind Facility on December 10, 2012. The Senate Wind Facility reached commercial operation in December 2012.

Senate Wind, LLC is party to the 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.

(10) Odell Wind Facility

The Odell Wind Facility is a 200 MW wind facility located near Windom, Minnesota, 230 km southwest of Mineapolis, Minnesota. The Odell Wind Facility reached commercial operation on July 29, 2016.

Odell Wind Farm LLC has entered into a PPA with Norther States Power Company under which all electricity and RECs produced at the facility are sold to Northern States Power Company. The term of the PPA is 20 years.

(11) Deerfield Wind Facility

The Deerfield Wind Facility is a 149.0 MW wind energy facility located in central Michigan, 180 km north of Detroit, Michigan. APUC first acquired an indirect interest in the Deerfield Wind Facility on October 19, 2015. The Deerfield Wind Facililty reached commercial operation in February, 2017.

All energy, capacity, and renewable energy credits from the project are sold to a local electric distribution utility, which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

### (iv) Renewable Energy Credits

**RECs** are tradeable commodities representing the generation of 1 MW-hr of electricity, and are used by utilities to satisfy compliance with Renewable Portfolio Standards ("**RPS**") where necessary. These 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 each produce and sell RECs through bilateral contracts.

## 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. APUC's solar generation facilities, the Cornwall Solar Facility, Bakersfield I Solar Facility and the Bakersfield II Solar Facility utilize photovoltaics which convert light into electric current using the photovoltaic effect. The array of a photovoltaic power system produces direct current ("**DC**") power which fluctuates with the sunlight's intensity. For practical use, commercial installations convert this DC generated power to alternating current ("**AC**"), through the use of inverters. Multiple solar cells are connected inside modules. Modules are wired together to form arrays, then connected to an inverter, which produces power at the desired voltage/frequency/phase.

### (ii) Principal Markets and Distribution Methods

The principal market for APUC's operational solar facility in Canada is Ontario for the Cornwall Solar Facility, and California for the Bakersfield I Solar Facility and the Bakersfield II 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.

(1) Ontario

The Independent Electricity System Operator (the "IESO") is an independent, non-profit corporation that is responsible for the real time operation, long term planning and procurement for Ontario's electricity system. The IESO is licensed by the OEB and it reports to the Ontario legislature through Ontario's Ministry of Energy.

(2) California

The California Independent System Operation ("**CAISO**") was formed in 1998 following a restructuring of the state electricity markets, and at the recommendation of the FERC. The CAISO operates as a non-profit public corporation responsible for operating the wholesale power system, maintaining the reliability of the grid, and planning for future demands. It is regulated by FERC.

### (iii) Material Facilities

(1) Cornwall Solar Facility

The Cornwall Solar Facility is a 10 MW ground mounted photovoltaic solar energy facility located near Cornwall, Ontario, 100 km southeast of Ottawa. The facility achieved commercial operation on March 27, 2014.

The Cornwall Solar Facility has a FIT contract with the IESO with a term of 20 years with a fixed power purchase rate throughout the term.

(2) Bakersfield I Solar Facility

The Bakersfield I Solar Facility is a 20 MW ground mounted photovoltaic solar energy 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.

The Bakersfield I Solar Project achieved commercial operation in April 2015 and has a PPA with Pacific Gas and Electric Company (" **PG&E**") with a term of 20 years from commencement of commercial operation. The PPA has a fixed power purchase rate throughout the term.

(3) Bakersfield II Solar Facility

The Bakersfield II Solar Facility is a 10 MW ground mounted photovoltaic solar energy 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, adjacent to the Bakersfield I Solar Facility.

The Bakersfield II Solar Project achieved commercial operation in January 2017 and has a PPA with a large investment grade electric utility in California with a term of 20 years from commencement of commercial operation.

### 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 of APUC'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 is also sold to onsite or adjacent third party thermal host facilities for use in production.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the California Public Utilities Commission ("**CPUC**") and FERC. The CAISO administers the wholesale electricity marketplace for the region.

(2) Connecticut

The electricity markets and transmission systems in Connecticut are governed by the Independent System Operator New England (" **ISO-NE**"). The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

#### (iii) Material Facilities

(1) Sanger Thermal Facility

The Sanger thermal cogeneration facility (the "**Sanger Thermal Facility**") is a 56MW natural gas-fired generating facility located in Sanger, California. The Sanger Thermal Facility was acquired by APUC on May 1, 2002.

The facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 PC Sprint gas turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, originally commissioned in 1991. The Sanger Thermal Facility has a firm capacity and energy PPA with PG&E 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 Facility") is a 71 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The facility was acquired by APUC on March 10, 2003.

The facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine both commissioned in 1990, and a 15 MW Solar Titan 130 combustion turbine installed in 2012.

The Windsor Locks Thermal Facility supplies thermal steam energy and the majority of the output from the Solar Titan combustion turbine to Ahlstrom Corporation ("**Ahlstrom**"), a leading paper and non-woven materials manufacturer, pursuant to a ground lease and an Energy Services Agreement (the "**ESA**"). Pursuant to the ESA, Ahlstrom leases the facility site to Algonquin Power Windsor Locks LLC and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Thermal Facility for use at its specialty fibers composites mill located adjacent to the Windsor Locks Thermal Facility. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Windsor Locks Thermal Facility.

With the current configuration, 90% of the output of the baseload electrical generation is generated by the Solar Titan combustion gas turbine and is sold to Ahlstrom. 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. Each MW generated by the Solar Titan combustion turbine qualifies for the production of RECs.

### (iv) Renewable Energy Credits

RECs are tradable commodities representing the generation of 0.75 MW-hr of electricity, and are used by utilities to satisfy compliance with **RPS** where necessary. Currently, the Windsor Locks Thermal Facility is qualified for Class III CT RECs. It produces and sells RECs through bilateral contracts.

## Business Development

### (i) Strategy

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

### (ii) Principal Market Environment

APUC 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 for the corporation. The Alberta Electric System Operator ("**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 per cent of electricity generation by 2030 come from renewable sources. The AESO's recommendations were endorsed by the Government of Alberta on November 3, 2016, resulting in the formation of the Renewable Electricity Program ("REP"), which is expected to lead to the development of 5,000 MW of renewable energy capacity by 2030. The first competitive solicitation is expected to commence in early 2017, with contracts awarded by the end of 2017.

In Saskatchewan, the vertically-integrated utility SaskPower has set a target of 50% of generation capacity to come from renewables by 2013, 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 is expected to commence in early 2017, with contracts awarded by the end of 2017. Nova Scotia also continues to offer its community FIT program, albeit on a smaller scale.

Within the United States, the most notable stimulus for the development of renewable power is the federal renewable electricity production tax credit ("**PTCs**" or "**Production Tax Credits**"), a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, and the federal investment tax credit ("**ITCs**" or "**Investment Tax Credits**"), a tax credit for qualified renewable energy facilities based upon a percentage of eligible capital costs. On December 18th, 2015, the United States Congress approved a five-year extension to the 30 percent ITC for solar energy properties and 2.3 cents per kilowatt-hour PTC for wind facilities. The ITC for solar energy will remain at 30 percent through 2018, before it phases down gradually to 10 percent in 2022. The PTC for wind energy will be at maintained at 2.3 cents per kilowatt-hour for projects on which construction is commenced prior to the end of 2016 before phasing down 20 percent per year and being eliminated at the end of 2019. 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 2016, 29 states plus Washington D.C. and three territories have adopted binding RPS targets, and eight additional states have taken on voluntary renewable portfolio goals. These targets range between 10% and 50% of retail sales to specific entities, to be achieved between 2015 and 2040.

APUC will continue to pursue development projects which provide the opportunity to exhibit accretive growth within these markets.

### (iii) Current Development Projects

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

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

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

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

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

(1) Amherst Island Wind Project

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

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

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

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

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

(2) Great Bay Solar Project

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

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

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

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

(3) Chaplin-Blue Hill Wind Project

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

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

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

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

(4) Val-Éo Wind Project

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

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

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely be comprised of ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

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

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

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

### 3.1.3 Specialized Skill and Knowledge

The Renewable Generation Group's employees, also have extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of the Renewable Generation Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Renewable Generation Group in-house.

The energy from wind aspect of the business of the Renewable Generation Group requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to the Renewable Generation Group in-house. On a more general level, the production of energy from all facilities requires specialized skill and knowledge, and the Renewable Generation Group has employed various personnel who have such skill and knowledge.

### 3.1.4 Competitive Conditions

Deregulation has increased 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 should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The U.S. Department of Energy ("**USDOE**") has found that most 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 USDOE 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. Additionally, programs and policies are evolving at all government levels, allowing for the trading of greenhouse gas credits created by renewable energy projects to be seen as part of the eventual solution.

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 not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of power generation do 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.

APUC believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.
APUC 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. It has experience and knowledge in the area. APUC will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APUC anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being supported by virtually every Canadian province and a significant number of U.S. States.

### 3.1.5 Cycles & Seasonality

#### (i) Hydroelectric Generating Facilities

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

#### (ii) Wind Power Generating Facilities

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

#### (iii) Solar Power Generating Facilities

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

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

### 3.1.6 Customers

Please see "Enterprise Risk Factors – Treasury Risk Factors – *Credit-Counterparty*" for a detailed description and discussion of the most significant customers of the Renewable Generation Group.

## 3.2 Liberty Utilities Group

### 3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water distribution and wastewater collection systems, electric distribution systems or gas distribution systems, are generally subject to economic regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a 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 and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure adequate supplies of water, electricity and natural gas together with financial security, transparency in the rate setting process and reasonable prices.

#### (i) Water Distribution and Wastewater Collection Systems

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is typically provided a service territory defined by a Certificate of Public Convenience and Necessity ("**CPCN**") which imposes an exclusive right and duty to serve in the service territory. A CPCN is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the Corporation's customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

#### (ii) Electric Distribution Systems

The electricity industry is highly regulated in the United States. The industry is regulated under strict standards at multiple levels - federal, state and sometimes local. Under the FPA, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability.

Generally, electricity distribution companies in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is typically provided a CPCN which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the electric service company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

#### (iii) Natural Gas Distribution Systems

The natural gas industry is regulated at multiple levels - federal, state and sometimes local. Under the U.S. Natural Gas Act, FERC regulates interstate transmission and wholesale sales of gas. Interstate pipeline safety is regulated by the Department of Transportation. State utility commissions regulate retail distribution and sales of natural gas and intrastate pipelines. The

federal pipeline safety requirements are often adopted by the state utility commissions and applied to intrastate pipelines and local distribution companies.

Generally, natural gas distribution companies in the United States operate as geographic monopolies within the areas in which they serve. A natural gas distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these natural gas service providers. Such agencies are charged with ensuring that natural gas services are provided at reasonable rates and quality to customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the natural gas utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

### 3.2.2 Description of Operations

#### Water Distribution and Waste Water 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). 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 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.

In respect of sewer or wastewater services, the sewage or wastewater produced by the customer flows through a buried service lateral line, which the line is owned and maintained by the customer, from the house or commercial space to the street. This line feeds into collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. These pipes generally slope at a grade of approximately 0.25% as gravity is generally relied on to facilitate flows. On long line runs where maintaining slopes would result in excessive depths below grade or to traverse variable terrain, the line may terminate at a lift station where wastewater is collected and then pumped up to feed into another line located closer to the surface level where the wastewater can continue to flow by gravity. This is typically referred to as a “force main”.

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 therewith enforced by the State agency to which Federal enforcement powers are delegated.

### (ii) Principal Markets and Regulatory Environments

The Corporation's water and wastewater facilities are located in the United States of America in the states of Arizona, Texas, Illinois, Missouri, Arkansas, and with the recent acquisition of Park Water, in the states of California and Montana. 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 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. A summary of the rates and tariffs for the wastewater treatment and water distribution utilities is attached in Schedule C.

(1) Arizona

The Arizona Corporation Commission ("**ACC**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The Arizona Department of Environmental Quality ("**ADEQ**") and the Arizona Department of Water Resources in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

(2) Texas

The Public Utility Commission of Texas ("**PUC Texas**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. This regulatory responsibility was transferred from the Texas Commission on Environmental Quality (the "**TCEQ**") to PUC Texas on September 1, 2014. The TCEQ has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(3) Arkansas

The APSCis the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Arkansas for rates and charges. The Arkansas Department of Health has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water treatment service providers, including those owned and operated by municipalities. The Arkansas Department of Environmental Quality is the primary regulator for all discharge permits including wastewater treatment utilities in Arkansas.

(4) California

The CPUC is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in California for rates and charges. The Division of Drinking Water of the California State Water Resources Control Board ("**SWRCB**") has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the California Safe Drinking Water Act and Title 17 and 22 of the California Code of Regulations (California has primacy) for all water service providers, including those owned and operated by municipalities. The jurisdiction respecting drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The SWRCB is the primary regulator for all discharge permits from drinking water systems in California.

(5) Montana

The Montana Public Service Commission ("**MTPSC**") is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Montana for rates and charges. The Montana Department of Environmental Quality has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Safe Drinking Water Act, for all water service providers, including those owned and operated by municipalities. The Montana Department of Environmental Quality is the primary regulator for all discharge permits in Montana.

### (iii) Material Facilities

(1) Gold Canyon Water System

The Gold Canyon waste water system (the "**Gold Canyon Water System**") is a wastewater treatment facility established in 1984 to serve a number of residential developments and an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona.

The Gold Canyon Water System currently serves over 7,500 residential and commercial connections. The treatment plant utilizes a biological nutrient removal process combined with a sequencing batch reactor with a treatment capacity of 1.9 million gallons per day ("**gpd**").

The Gold Canyon Water System is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on two neighboring golf courses. Excess reclaimed water is recharged (put back into the ground to replenish underground water) via three recharge ponds. The treatment facility operates under ADEQ – Aquifer Protection Permits and Reuse Permits.

(2) LPSCo Water & Wastewater Systems

The LPSCo System located in the city of Goodyear, 15 miles west of Phoenix, Arizona whose service area includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County.

*Connection Base*

The LPSCo System presently serves approximately 19,000 water and 22,300 wastewater connections. The wastewater system has permitted capacity of 54.1 million gpd. The water infrastructure system includes a total of twelve active wells, a 6.3 million gallon reservoir and a 4.0 million gallon reservoir which provides water to the current connection base through a single pressure zone. The LPSCo System now operates at approximately 95% of design capacity. Construction began in April 2016 to expand the treatment capacity from 4.2 million gallons per day to 5.8 million gallons per day. Construction will finish in 2017.

*Rate Case*

On February 28, 2013, the LPSCo System filed a general rate case with the ACC seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application sought for an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. In April 2014 the ACC approved a $1.8 million increase in rates effective on May 1, 2014.

(3) Rio Rico Water & Wastewater Systems

The Rio Rico water & wastewater systems (the "**Rio Rico System**") is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona.

*Connection Base*

The Rio Rico System serves approximately 7,000 water and 2,300 wastewater connections in the community of Rio Rico, Arizona. The Rio Rico System has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

*Rate Case*

On October 28, 2015, the Rio Rico Water and Wastewater System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, a 10.8% return on equity ("ROE") and 70% equity. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case sought to recover increased operating costs and capital improvements. The rate case also sought approval for the fair value Arizona rate evaluation model ("FARE"), a purchased power adjuster mechanism ("PPAM") and a property tax adjuster mechanism ("PTAM"). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.98 million revenue increase. A Recommended Opinion and Order ("ROO") was issued in October 2016 accepting the settlement. A final decision was issued on October 27, 2016 approving the settlement, with implementation of new rates in November 2016. The previous rate case was based on a test year ending February 2012.

(4) Black Mountain Sewer System

The Black Mountain sewer system (the "**Black Mountain System**") is a wastewater facility located in Carefree, Arizona.

*Connection Base*

The Black Mountain System serves approximately 2,500 wastewater connections in the community of Carefree, Arizona.

*Rate Case*

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

(5) Bella Vista Water System

The Bella Vista water system (the "**Bella Vista System**") is a regulated water utility in Sierra Vista, Arizona.

*Connection Base*

The Bella Vista System serves approximately 9,700 water connections in the community of Sierra Vista, Arizona.

*Rate Case*

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

*Financing*

Outstanding third party indebtedness at The Bella Vista Water System consists of U.S. $0.7 million of Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10% and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears. On February 8, 2017, all remaining principal on the Bella Vista Water unsecured notes were fully repaid.

(6) Pine Bluff Water System

The Pine Bluff water system (the "**Pine Bluff Water System**") is a regulated water utility located in the City of Pine Bluff, Arkansas in Jefferson County. The system is regulated by the Arkansas PSC and has a franchise agreement with the City of Pine Bluff, Arkansas.

*Connection Base*

The Pine Bluff Water System serves a population of over 47,000 people comprising approximately 18,800 connections. During the year ended December 31, 2016, the Pine Bluff Water System's largest 10 connections represent approximately 24% of its total annual sales of approximately US$9.9 million. Its largest customers are a food processing company, public works facilities and a university.

*Rate Case*

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

(7) Park Water System

On January 08, 2016, the Liberty Utilities Group closed a previously announced agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. (“**Park Water**”). Park Water owns and operates three regulated water utilities

engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Park Water provides, owns and operates the water system in central Los Angeles. Apple Valley Ranchos Water Company, now known as Liberty Utilities (Apple Valley Ranchos Water) Corp. (“Apple Valley”), owns and operates the water system in Apple Valley, California. Mountain Water Company (“Mountain Water”) owns and operates the water system serving the municipality of Missoula, Montana. Mountain Water and Apple Valley are wholly-owned by Park Water.

*Connection Base*

The three utilities collectively serve approximately 70,700 customer connections and have more than 1,000 miles of distribution mains.

Mountain Water Company is currently the subject of a condemnation lawsuit filed by the city of Missoula. Please see " *4.2.2 Operational Risk - Regulatory Risk - Condemnation Expropriation Proceedings*" and "*9.2 Regulatory Actions*" for a detailed description and discussion of the condemnation proceedings.

## 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 system’s network carries electricity from the transmission system and delivers it to consumers or other end users. Typically, the network includes medium-voltage (less than 50 kV) power lines, electrical substations, various line apparatus (reclosers, fuses, lightning arrestors), and distribution transformers (pole mounted or pad-mounted), low-voltage (less than 1 kV) secondary distribution wiring and then electric meters used for billing.

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 which can use various fuels such as water (hydro), natural gas, coal, bio-mass, wind, nuclear and solar. 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, for example.

The electrical distribution utilities located in California, New Hampshire, Missouri, Arkansas, Oklahoma and Kansas 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 Corporation 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, pro-formed 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 3 years. A summary of the rates and tariffs for the electric distribution utilities is attached in Schedule D.

(1) California

The CPUC regulates investor owned utilities in California and approves the rate of return and the rate base which affects the profitability of the utility.

Energy Cost Adjustment Clause (“**ECAC**”) is an annual filing that sets rates to recover the next year’s fuel and purchased power costs in addition to setting rates to recover or refund any under/over recovery of previous year’s fuel and purchased power costs.

Post Test Year Adjustment Mechanism (“ **PTYAM**”) allows the CalPeco Electric System to update its rates annually by a cost inflation index. In addition, rates are updated to recover the return on investment and associated depreciation of major capital projects that are placed in service and meet a certain cost threshold.

The Base Revenue Requirement Balancing Account (“ **BRRBA**”) removes the seasonal variations of the revenues and flattens the net revenue (minus fuel, purchased power, and ECAC) to a monthly rate of $4.5 million or $53.4 million annually. This eliminates the risk of revenue variations associated with seasonal weather changes.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. New Hampshire introduced “retail choice” for customers in 1998. Utility companies are allowed to file distribution rate cases from time to time as the companies determine a need to request adjustments to base rates. There are a number of adjustment factors also in rates, for reliability enhancement programs, vegetation management, energy efficiency and low income programs, all of which are reconciled on an annual basis. Electricity distribution companies are also required to provide electricity commodity service for its customers who do not elect to take service from a competitive supplier. Costs for commodity service are recovered on a direct pass through basis.

(3) Missouri (as of January 1, 2017 following the Empire Acquisition)

The Corporation's Missouri operations are regulated by the MPSC.

The rates and fees for providing electric service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover fuel costs are charged through the Fuel Adjustment Clause (“**FAC**”).

(4) Arkansas (as of January 1, 2017 following the Empire Acquisition)

The Arkansas PSC is the primary regulatory agency with jurisdiction over the investor owned electric utilities in Arkansas for rates and charges.

(5) Oklahoma (as of January 1, 2017 following the Empire Acquisition)

The Corporation Commission of Oklahoma ("OCC") is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Oklahoma.

(6) Kansas (as of January 1, 2017 following the Empire Acquisition)

The State Corporation Commission of the State of Kansas ("KCC") is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Kansas.

### (iii) Material 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. The distribution system is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving approximately 48,800 connections.

*Connection Base*

CalPeco Electric System’s connection base of approximately 48,800 connections is primarily residential with large commercial accounts limited to less than 18% of gross revenues. The commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores. The CalPeco Electric System's largest 10 connections represent approximately 9.3% of its total annual sales of approximately U.S. $82.7 million. Its largest customers are major ski resorts and large region school district.

*Rate Case*

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

increase. The increase reflects a 10.0% ROE and 52.5% equity. A final permanent rate decision from the CPUC was received in the fourth quarter of 2016, approving the settlement with a revision to the treatment of tax repairs in rates. This revision lowered the approved revenue increase to U.S. $8.3 million. The new permanent rates were implemented January 2017, and reflect retroactive effectiveness to the first quarter of 2016.

*Kings Beach Generation*

The CalPeco Electric System has a local-area emergency backup generation facility at Kings Beach (the " **King Beach Facility**")in Placer County, California. The facility consists of six Caterpillar 3516 Engine diesel generation units with a total nameplate capacity of 12 MW. The units were installed in November 2008 at a cost of U.S. $16.5 million and have an estimated useful life of 30 years. The repowered facility meets all California environmental standards.

In the event of a system outage, the Kings Beach Facility is able to provide limited back-up generation support to the CalPeco Electric System's service territory until baseload power is restored. The facility includes quick-start technology which facilitates this support function. The new units are designed to be online and operating within 1 minute of being activated. The Kings Beach Facility has historically run an average of 200 hours per year.

*Energy Cost Adjustment Clause*

ECAC is an annual filing that sets "base rates" to recover the next year's fuel and purchased power costs in addition to setting "amortization rates" to recover or refund any under/over recovery of previous year's fuel and purchased power costs. Rates are effective January 1st of every year.

*Post Test Year Adjustment Mechanism*

In years where the CalPeco Electric System does not file a general rate case, its rates are updated on January 1st to reflect inflationary increases to its administrative, operations, and maintenance costs. The inflationary adjustment is set by the use of an index, less a presumed efficiency offset.

The CalPeco Electric System may also file for an annual increase in rates to recover its investment costs in material capital projects. This increase is subject to a materiality threshold.

*Base Revenue Requirement Balancing Account*

BRRBA is used to record the difference between the CalPeco Electric System's CPUC authorized annual base rate revenue requirements and the annual recorded revenue from base rates. The disposition of the balance in the BRRBA is addressed by an annual filing.

*PPA*

During 2015, the Corporation entered into a new multi-year Services Agreement with NV Energy commencing January 2016. The PPA obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, combined with the solar project described below, satisfy the current California Renewables Portfolio Standard requirement for the five-year term of the PPA.

The CalPeco Electric System filed an Application with the CPUC in Q2 2015 for authorization to enter into a multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV ESA as energy purchase costs. CPUC approval was received in the fourth quarter of 2015 for the new PPA.

*Solar Project*

The CalPeco Electric System filed an Application with the CPUC in 2Q15 for the issuance of a Certificate of Public Convenience and Necessity to acquire, own, and operate a solar power generation station with a total generation capacity of up to 60MW (the Solar Project). The application requested authorization for rate recovery of the costs that the Calpeco Electric System will incur to acquire, own, and operate the Solar Project which is owned by Luning Energy, LLC. The application along with the Order issued approving the new PPA with NV Energy allows the Calpeco Electric System to continue procurement of its energy supply in a cost-effective manner for its customers while also allowing the utility to meet its RPS requirements. An order approving the Solar Application (revised to 50MW in a settlement) was issued in December 2015. The project achieved commercial operation in Q1 2017. On January 31, 2017, the Federal Energy Regulatory Commission authorized Luning Energy LLC to make power sales to the CalPeco Electric System pursuant to the PPA.

*Financing*

The CalPeco Electric System entered into a long term debt private placement in an amount of U.S. $70.0 million on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate, interest only, and split into two tranches, U.S. $45.0 million of ten year 5.19% notes and U.S. $25.0 million of 5.59% fifteen year notes.

(2) Granite State Electric System

The Granite State Electric System provides distribution service to approximately 44,900 connections in 21 communities located in two franchise service areas in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. Across approximately 810 square miles of service area, the Granite State Electric System's assets consist of 908 miles of overhead distribution lines, 231 miles of underground distribution lines, 15 distribution substations, 37 distribution circuits and 9 sub-transmission circuits.

*Connection Base*

The Granite State Electric System's customer base consists of a mixture of residential, commercial and industrial customers. The system's residential customer base represents approximately 38,300 connections, while the commercial and industrial customer base represents approximately 6,700 connections. The commercial and industrial connections are a mix of commercial, retail, medical, education and manufacturing with its largest 10 connections representing approximately 18.6% of its total annual sales of approximately U.S. $88.9 million. Its largest customers are a world renowned medical facility and an Ivy League educational institution.

*Rate Case*

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

*Default Service Adjustment Provision*

Granite State Electric System is required to provide electric commodity supply (Default Service) for all customers who do not choose to take supply from a competitive supplier in the New England power market. The competitive market is overseen by the ISO-NE. As an electric distribution utility, Granite State Electric System is required to participate in the ISO-NE market and abide by its rules under FERC. The Granite State Electric System 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.

*Financing*

Outstanding third party indebtedness at the Granite State Electric System consists of unsecured notes issued in three tranches for an aggregate amount of U.S. $15.0 million: U.S. $5.0 million bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5.0 million bearing an interest rate of 7.94%, maturing July 1, 2025; and U.S. $5.0 million bearing an interest rate of 7.30%, maturing June 15, 2028. The notes are interest only and payable semi-annually.

(3) Empire District Electric System (as of January 1, 2017)

Empire operates its businesses as three segments: electric, gas and other. Empire is a public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, it provides water service to three towns in Missouri. The Empire District Gas Company is a wholly owned subsidiary engaged in the distribution of natural gas in Missouri. The other segments consists of a fiber optics business:

| | |
|---|---|
| Electric segment sales* | 92.9% |
| On-system revenues | 86.6% |
| SPP IM revenues | 4.0 |
| Other revenues | 2.0 |
| Gas segment sales | 6.0 |
| Other segment sales | 1.1 |

*Sales from the electric segment include 0.3% from the sale of water.

The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and the FERC.

*Connection Base*

The electric operations serve approximately 170,000 customers as of December 31, 2016, and the 2016 electric operating revenues were derived as follows:

| Customer Class | % of revenue |
|---|---|
| Residential | 41.8% |
| Commercial | 30.4 |
| Industrial | 15.2 |
| Wholesale on-system | 3.5 |
| Wholesale off-system | 4.3 |
| Miscellaneous sources, primarily public authorities | 2.7 |
| Other electric revenues | 2.1 |

The retail electric revenues for 2016 by jurisdiction were as follows:

| Jurisdiction | % of revenue |
|---|---|
| Missouri | 90.1 % |
| Kansas | 4.4 |
| Oklahoma | 2.6 |
| Arkansas | 2.9 |

*Rate Case Matters*

2015 Rate Case: On October 16, 2015, Empire filed a request with the MPSC for changes in rates for its Missouri electric customers, seeking an annual increase in total revenue of approximately $33.4 million, or approximately 7.3%. On June 21, 2016, Empire announced that it had filed a Unanimous Stipulation and Agreement (the "**Empire Rate Case Agreement**") with the MPSC. The MPSC issued an order approving the Empire Rate Case Agreement on August 10, 2016 with rates effective September 14, 2016. The Empire Rate Case Agreement allows an annual increase in base revenues of approximately $20.4 million, or 4.46%. Base revenues established by the agreement are lower than the originally requested level of $33.4 million due primarily to lower fuel and purchased power costs than those built into current customer rates. The offsetting effect of reduced revenues and reduced fuel costs results in little impact to gross margin. The most significant factor driving the rate request was the cost associated with the conversion of the Riverton Unit 12 natural gas combustion turbine to combined cycle operation. The Empire Rate Case Agreement calls for the Fuel Adjustment Charge to remain in effect. In addition, a tracking mechanism for non-labor operating and maintenance expenses for the Riverton 12 Combined Cycle Unit will continue and tracking of pension and other post-employment benefit expenses will continue.

*2015 Solar Rebate Tariff*

On May 5, 2015, Empire filed a proposed solar rebate tariff with the MPSC and requested expedited treatment. On May 6, 2015, the MPSC granted Empire's request for expedited treatment of the tariff filing and approved the tariff, effective May 16, 2015. The law provides a number of methods that may be utilized to recover the associated expenses. It is expected that any costs will be recoverable in rates.

*Integrated Resource Plan and Missouri Energy Efficiency Investment Act*

Empire filed its most recent Integrated Resource Plan (IRP) with the MPSC on April 1, 2016. The IRP analysis of future loads and resources is normally conducted once every three years.

*Kansas*

On January 11, 2017, Empire filed a request to implement a rider, the Asbury Environmental and Riverton Rider (AERR), in place of the Asbury Environmental Rider (AER) currently in effect in its Kansas jurisdiction. If approved the new rider will provide a mechanism to begin recovering costs related to the $168 million combined cycle generating unit at the Riverton Power Plant,resulting in an increase in annual revenues of $1.87 million. The KCC will conduct a review of the filing prior to implementation of the new rider. The new rider is expected to take effect no later than 210 days from the date of filing.

*2015 Ad Valorem Tax Surcharge*

On January 22, 2015, Empire filed an Application with the KCC requesting approval of an Ad Valorem Tax Surcharge (" **AVTS**"). The request sought approval for an annual increase of $0.27 million related to increases in Ad Valorem taxes which exceed amounts currently included in base rates. On February 19, 2015, the KCC approved the request. The new rate was effective February 23, 2015. On January 21, 2016, Empire filed an Application with the KCC requesting approval for a revision to the AVTS. The request sought approval for an annual increase of an additional $0.2 million related to increases in Ad Valorem taxes which exceed amounts currently included in Empire's AVTS rider. This is an annual filing.

*2014 Environmental Cost Recovery Rider*

On December 5, 2014, Empire filed an Application with the KCC requesting approval of the proposed Asbury Environmental Cost Recovery ("**AECR**") tariff rider. The request sought approval for recovery of the jurisdictional portion of annual carrying

costs (rate of return, income taxes, and depreciation) of approximately $0.86 million, associated with investment in the Asbury AQCS. A Commission Order was received April 15, 2015 approving the rider in the amount of $0.78 million effective June 1, 2015.

*Oklahoma*

On December 21, 2016, Empire filed a request with the OCC for changes in rates for its Oklahoma electric customers, seeking an increase in annual revenues of approximately $3.8 million, or approximately 27.58%. Primary drivers for this case include the $112 million Air Quality Control System (AQCS) at the Asbury Power Plant, the $168 million combined cycle generating unit at the Riverton Power Plant; upgrades to financial, asset, and work management software systems; and other reliability and system improvements to serve customers.

*Arkansas*

*2016 Cost Recovery Rider*

On July 21, 2016, Empire filed a request with the Arkansas Public Service Commission to implement a cost recovery rider for the conversion of the existing Riverton Unit 12 to combined cycle operation. The rider request was approved on October 25, 2016 and Empire began collecting approximately $0.6 million of additional annual revenue on November 1, 2016.

*Municipal Franchise Taxes*

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Municipal franchise taxes of $11.1 million, $11.4 million and $11.8 million were recorded for each of the years ended December 31, 2016, 2015 and 2014, respectively.

*Fuel and Purchased Power*

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. SPP Integrated Marketplace purchased power is also included in fuel and purchased power costs. The net effects of Empire's SPP Integrated Marketplace activity, including SPP Integrated Marketplace net revenue and net purchased power costs, flow through the fuel recovery mechanisms in each state.

In Missouri, the MPSC establishes a base cost for the recovery of fuel and purchased power expenses used to supply energy for the fuel adjustment clause (FAC). Beginning with a 2015 rate order, certain transmission costs are also included in the base cost. The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered from or refunded to customers when the fuel adjustment clause is modified.

In the Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations.

Similar fuel recovery mechanisms are in place for Empire's Oklahoma, Arkansas and FERC jurisdictions.

*Derivatives*

Empire utilizes derivatives to help manage its natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business, or on the spot market. Empire also acquires Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power purchased from the SPP Integrated Marketplace

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the balance sheet at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability (“cash-flow” hedge); or (2) an instrument that is held for non-hedging purposes (a “non-hedging” instrument). Empire records the mark-to-market gains or losses on derivatives used to hedge fuel and congestion costs as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through the fuel adjustment mechanism.

Empire also enters into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered

to be normal purchase normal sales (NPNS) transactions. If these transactions do not qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

*Fuel, Materials and Supplies*

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost.

## 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.

Because gas flowing from higher to lower pressure is the fundamental principle of the natural gas delivery system, compressor stations may be located every 50-60 miles along the pipelines to boost pressure that is lost through friction. Also 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. The gas is transported from various sources at high pressures through transmission lines and is then reduced through gate stations to distribution pressures.

The gas from the gate stations is then delivered through distribution lines to the customer where the gas pressure is again lowered through district regulator stations and/or meter regulators for use by the customer. Typically, the distribution network operates pipelines, gate stations, district regulator stations, peak shaving plants and natural gas meters.

The gas distribution utilities owned by the Corporation 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 Corporation 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. A summary of the rates and tariffs for the Corporation's natural gas distribution utilities is attached in Schedule E.

(1) New Hampshire

In New Hampshire, gas utilities are regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed purchased gas adjustment clause ("PGA").

(2) Illinois

The Corporation's Illinois operations are regulated by the Illinois Commerce Commission.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(3) Iowa

The Corporation's Iowa operations are regulated by the Iowa Utilities Board.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(4) Missouri

The Corporation's Missouri utility operations are regulated by the MPSC.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(5) Georgia

The Corporation's Georgia operations are regulated by the Georgia Public Service Commission (" **GPSC**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(6) Massachusetts

The Corporation's Massachusetts operations are regulated by the Commonwealth of Massachusetts. The Massachusetts Department of Public Utilities ("MDPU") has regulatory jurisdiction over all public utilities and common carriers operating in the Commonwealth, which jurisdiction includes the establishment of approved tariffed rates for the purpose of billing customers.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

### (iii) Material Facilities

(1) EnergyNorth Gas System

The EnergyNorth Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 90,100 connections in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord, New Hampshire. The EnergyNorth Gas System is the largest natural gas distribution utility in the State, with a distribution system consisting of 2,140 miles of distribution pipelines, 2.8 miles of transmission pressure gas pipelines and eight city gate stations, or distribution supply points.

*Customer Base*

The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 81,000 connections, while the commercial and industrial customer base represents approximately 9,100 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The EnergyNorth Gas System's largest 10 connections represent approximately 3.0% of its total annual sales of approximately U.S. $106.6 million. Its largest customers are a technology company and multiple public works facilities.

*Rate Case*

On August 1, 2014, the EnergyNorth Gas System in New Hampshire filed an application for a total increase in revenue of U.S. $16.1 million, or approximately 9.6%. This proposed increase consisted of U.S. $13.4 million of permanent base distribution rates and a step increase of U.S. $2.7 million for investments made during a pro forma period. The application included a revenue decoupling proposal and sought recovery of capital costs related to the conversion of the system to the Corporation's ownership. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates. On June 26, 2015, an Order was issued approving a settlement agreement allowing for a U.S. $12.4 million revenue increase effective July 1, 2015.

*Energy Cost Adjustment Clause*

The cost of gas ("COG") delivered to customers is recovered when billed to “firm” gas customers through the operation of gas adjustment clauses included in utility tariffs. The COG provision requires periodic reconciliation of recoverable gas costs and COG revenues.

*Growth Projects*

The EnergyNorth System in New Hampshire recently filed two applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in November 2016 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. This docket is expected to conclude in 2017. Another application was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham, which has been approved by the NHPUC.

(2) Midstates Gas System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 82,900 connections in 190 communities in the states of Illinois, Iowa and Missouri. 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. The Midstates Gas System has a distribution system consisting of 2,795 miles of distribution pipelines, 243 miles of transmission pressure gas pipelines and 102 city gate stations, or town border supply points.

*Customer Base*

The Midstates Gas System serves approximately 22,600 connections in Illinois, 4,400 connections in Iowa and 55,900 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of the 82,900 connections, approximately 73,300 (88%) are residential connections, while 9,700 (12%) are commercial and industrial connections. The commercial and industrial connection base is a diversified mix of retail, medical, education and industrial uses. The Midstates Gas System's largest 10 connections represent approximately 6.1% of its total annual sales of approximately U.S. $63.8 million. Its largest customers are a biotechnology company and a manufacturing company.

*Energy Cost Adjustment Clause*

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. An annual reconciliation is filed based on the 12 months ended December.

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 12 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. An annual reconciliation is filed based on the 12 months ended August of each year.

*Derivatives*

Financial hedges for the natural gas business are recorded at fair value on the balance sheet. Because the MIdstates Gas System has a commission approved natural gas cost recovery mechanism (PGA), it records the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to customers for natural gas costs and actual natural gas expense which is trued up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that the Corporation will be recovering its costs after the annual true up period (subject to a prudency review by the MPSC).

Pursuant to the provisions of the PGA, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments) are reflected as a regulatory asset or liability.

*Rate Case*

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

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

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

(3) Empire District Gas System (as of January 1, 2017)

The Empire District Gas Company (EDG) is a wholly owned subsidiary of the Empire engaged in the distribution of natural gas in Missouri.

*Customer Base*

The Empire District Gas System serve approximately 43,000 customers as of December 31, 2016, and its 2016 gas operating revenues were derived as follows:

| Customer Class | % of revenue |
|---|---|
| Residential | 63.0% |
| Commercial | 24.6 |
| Industrial | 0.7 |
| Transportation | 9.9 |
| Miscellaneous | 1.8 |

*Energy Cost Adjustment Clause*

Fuel expense for Empire's gas segment is recognized when the natural gas is delivered to customers, based on the current cost recovery allowed in rates. 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.

(4) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services to approximately 64,500 connections in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, and Hamilton, GA. The regulated Peach State Gas System has a distribution system consisting of approximately 1,200 miles of distribution pipelines, approximately 70 miles of transmission pressure gas pipelines and four city gate stations, or distribution supply points.

*Customer Base*

The Peach State Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 60,200 connections, while the commercial and industrial customer base represents approximately 4,300 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The utility also maintains and operates the distribution system for a large US Army military base, consisting of approximately 116 miles of distribution pipelines, through a special privatization contract. The Peach State Gas System's largest 10 connections represent approximately 10.2% of its total annual sales of approximately U.S. $68.6 million. Its largest customers are poultry and textile producers.

*Rate Case*

The Peach State Gas System's rates are reviewed and updated annually through a tariff provision called the Georgia Rate Adjustment Mechanism ("**GRAM**"). 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 mechanism includes a provision to "true up" revenues in the subsequent year to capture or refund under or over collections. The annual GRAM filing is due October 1st of each year and the rates approved through the filing go into effect February 1st of the following year. The mechanism includes a forward looking view of cost of service based on approved inflation factors and also includes certain forecasted capital expenditures.

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

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

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

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. The filing is made each February 15th and the rate adjustment, calculated using a 10.7% ROE, takes effect on October 1st of the same year. The projects associated with the program are due to be completed in 2017, and the associated rate base under this program will be rolled into the annual GRAM filing in 2018.

*Energy Cost Adjustment Clause*

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). The cost of gas delivered to customers is recovered when billed to “sales” gas customers through the operation of PGA clauses included in utility tariffs. The PGA requires a change in rates at least every three months. Each year the utility files a gas supply plan on July 1st with an effective date of October 1st.

(5) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 54,700 customers in six communities located in the southeastern portion of Massachusetts. The New England Gas System’s distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas Systems receives gas at five delivery points or gate stations along the Algonquin Gas Transmission Corporation (Spectra Energy) transmission system (not affiliated with APUC).

*Customer Base*

The New England Gas System's customer base consists of a mixture of residential, commercial, and industrial customers. The system's residential customer base represents approximately 51,000 connections, while the commercial and industrial customer base represents approximately 3,700 connections. New England Gas System’s distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas System's largest 10 connections represent approximately 4.6% of its total annual sales of approximately U.S. $48.8 million. Its largest customers are waste management and textile companies.

*Rate Case*

On July 16, 2015, the New England Gas System filed an application with the MDPU seeking an increase in revenue of U.S. $11.8 million, or 14.6%, based on a test year ending December 31, 2014, adjusted for known and measurable changes in calendar 2015. This application represented the first rate case under the Liberty Utilities Group's ownership. It sought an increase in its general rates for increasing capital costs associated with maintaining the infrastructure and increases in operating and maintenance expenses. The increase reflected a requested return on equity of 10.4% and a debt/equity structure of 45%/55%. An all-party settlement was achieved and filed in December 2015. The settlement included a two-step revenue increase totaling $8.3 million, premised upon a 9.6% return on equity on 50% of capital. A $7.8 million revenue increase was effective March 1, 2016, and a further $0.5 million revenue increase was effective March 1, 2017, contingent upon specified employee additions. On February 10, 2016, an order was issued approving the settlement agreement.

*Energy Cost of Gas Adjustment Clause*

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 (May and November) and more frequently if the monthly gas cost forecast differs from the originally forecasted by more than5%.

*Financing*

The New England Gas System currently has outstanding indebtedness in the form of first mortgage bonds consisting of three tranches for an aggregate amount of U.S. $19.5 million: U.S. $6.5 million, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7.0 million, bearing an interest rate of 7.99%, maturing September 15, 2026; and U.S. $6.0 million, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.

## Natural Gas and Electric Transmission

### (i) Method of Providing Services and Distribution 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. Under the FERC environment, a shipper must have the good right or title to the gas for transportation. Under the

FERC regulations, a considerable amount of daily and current information about each pipeline system capacity and related shipper and capacity information is available on their public Electronic Bulletin Boards or public websites.

Electric Transmission service is subject to Open Access Transmission Tariffs ("OATT"). With the Empire Acquisition, as of January 1, 2017 APUC acquired transmission facilities in SPP.

The Empire transmission facilities are located within a four state area of Missouri, Kansas, Oklahoma, and Arkansas and Empire is a member of the SPP. The transmission facilities range in voltage from 69 kV up to 345 kV and 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.

#### (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.

Empire's electric transmission operates in the SPP Market and is a member of SPP. The SPP Market covers approximately 550,000 square miles from the Canadian border in Montana and North Dakota in the north to parts of New Mexico, Texas and Louisiana in the south. Southwest Power Pool and its diverse group of member companies coordinate the flow of electricity across 60,000 miles of high-voltage transmission lines spanning 14 states. Empire District Electric is subject to four different states regulatory bodies, SPP Regional Entity (SPP RE) for NERC compliance, SPP Market Rules, and the FERC.

#### (iii) Material Facilities

Empire District Electric facilities consist of more than 1,200 miles of facilities that qualify as transmission and range in voltage from 69 kV to 345 kV. The majority of the Empire District transmission is 161 kV. The transmission facilities consist of terminal equipment, transformers, lines, towers,, and associated equipment consistent with owning and operating a high voltage transmission system.

### 3.2.3 Specialized Skill and Knowledge

The Liberty Utilities Group requires specialized knowledge of the utility systems served including electrical, gas or water and waste water distribution. 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 utility trained personnel at its corporate offices to support the expanded portfolio of utility assets.

### 3.2.4 Competitive Conditions

The Liberty Utilities Group’s businesses have geographic monopolies in their service territories and are therefore insulated from competition. 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 regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives.

### 3.2.5 Cycles & Seasonality

#### (i) Water & 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 above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, the Central Basin and Apple Valley facilities in California, a weather normalization adjustment is applied to customer bills that adjust commodity rates to

stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Distribution Group operates have approved mechanisms to mitigate demand fluctuations.

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. Prior to January 1, 2013, CalPeco Electric System was exposed to volume sales risk related to seasonal weather variations. Effective on January 1, 2013, pursuant to the CPUC General Rate Case decision, a BRRBA rate mechanism has been implemented. The BRRBA removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power, and the ECAC deferral) to a monthly amount of approximately U.S, $4.5 million or U.S. $53.4 million annually. 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 Granite State Electric System offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. These programs are funded via a charge in distribution rates known as the systems benefit charge, which applies to all utilities. This mechanism provides for an annual reconciliation of costs. The company has an opportunity to earn a performance incentive if it is successful in achieving its annual energy efficiency targets.

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

### 3.2.6 Customers

The Liberty Utilities Group's businesses derive their revenues from a diverse residential, commercial and industrial customer base. For the twelve months ended December 31, 2016, electricity sales and distribution were approximately 50% from residential customers and 50% from commercial and industrial customers; natural gas sales and distribution were approximately 50% from residential customers and 50% from commercial and industrial customers; and water and waste water sales were approximately 69% from residential customers and 31% from commercial and industrial customers.

The EnergyNorth Gas System offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. These programs are funded via a charge in rates with an annual reconciliation of costs. The company has an opportunity to earn a performance incentive if it is successful in achieving its annual energy efficiency targets.

## 3.3 Related Party Transactions

(i) Emera Inc.

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

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

(ii) Equity-method investments

The Corporation provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Corporation charged its equity-method investees $3.3 million as compared to $2.0 million during the same period in 2015.

(iii) Trafalgar

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

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

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

(iv) Long Sault Hydro Facility

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

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

## 3.4 Principal Revenue Sources

As at March 10, 2017, APUC owned, directly or indirectly interests in thirty-seven renewable generation facilities and four thermal generation facilities including those identified in “Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments”, three electrical distribution utilities, seven natural gas distribution utilities, 1 propane gas distribution utility, and 23 water distribution and wastewater utilities.

For the year ended December 31, 2016, APUC derived approximately 22.2% of its revenues from its interests in power generation facilities (21.7% in 2015), 20.8% of its revenues from electrical distribution utilities ( 21.8% in 2015), 37.0% of its revenues from natural gas distribution utilities (45.2% in 2015), and 16.6% of its revenues from its interests in water distribution and wastewater utilities ( 7.6% in 2015).

The purchase of electricity and natural gas by the Corporation's electric distribution and natural gas distribution system 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 utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. Adjusting for the impact of these commodity costs APUC derived approximately 27.6% of its revenues from its interests in power generation facilities ( 29.9% in 2015), 13.5% of its revenues from electrical distribution utilities (14.2% in 2015), 33.0% of its revenues from natural gas distribution utilities ( 38.0% in 2015), and 21.2% of its revenues from its interests in water distribution and wastewater utilities (12.1% in 2015).

## 3.5 Environmental Protection

APUC'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.

APUC 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.

Environmental protection requirements did not have a significant financial or operational effect on APUC's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2016 . Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets are expected to increase the earnings and benefit the competitive position of APUC.

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities *(see Enterprise Risk Factors - Environmental)*. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

To manage these risks responsibly, APUC has ensured that environmental and compliance departments have been established within the different subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required.

## 3.6 Employees

APUC's Executive Management Group consists of nine individuals including the Presidents of the Renewable Generation Group and the Liberty Utilities Group. As at December 31, 2016, APUC employed 1,490 people.

The Renewable Generation Group employs a total of 150 employees. All of the employees of the Renewable Generation Group are non-unionized.

The Liberty Utilities Group employs a total of 1,200 employees. The Liberty Utilities Group employees are non-unionized with the exception of: 60 employees at the CalPeco Electric System, 43 employees at the Midstates Gas System, 183 employees at the EnergyNorth Gas and Granite State Electric System, and 80 employees at the New England Gas System.

The Corporate and shared services groups consist of an additional 140 employees located at the APUC corporate offices in Oakville, Ontario.

With the closing of the Empire Acquisition, the Liberty Utilities Group added 735 employees, of which 357 are unionized.

## 3.7 Foreign Operations

For the twelve months ended December 31, 2016 , approximately 84% of EBITDA and 83% of cash flow are generated from operations located in the United States and are denominated in U.S. Dollars.

## 3.8 Economic Dependence

The largest customer on a percentage basis is PJM, which totalled 2.9% of gross revenues in the year ended December 31, 2016. Receivables from PJM are invoiced monthly and generally collected within 14 days. The second largest customer on a percentage basis is Manitoba Hydro which totalled 2.6% of gross revenues in the year ended December 31, 2016. Receivables are invoiced monthly and generally collected within 20 days. The third largest customer is Quebec Hydro, totaling 2.5% of gross revenues in the year ended December 31, 2016. Receivables are invoiced monthly and generally collected within 21 days.

Details on the credit ratings of the above customers can be found in "Risk Factors – *Credit-Counterparty*".

Otherwise, APUC does not believe it is substantially dependent on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or license or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

## 3.9 Social or Environmental Policies

APUC has formal policies and procedures that support its commitment to corporate responsibility (" **CR**"). APUC's Code of Business Conduct and Ethics is the foundation of the Corporation's CR framework. As a condition of employment, all employees 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. During the course of business, any compliance exceptions are reviewed and managed promptly.

APUC'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.

APUC has an Environmental, Health and Safety Group that reports independently to the President of the appropriate business. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

APUC is actively involved in CR. Using the Global Reporting Initiative ("**GRI**"), the Corporation formally tracks several GRI indicators, and in 2014 began publishing a CR report. With CR as an element of the Corporations's decision making the Corporation reduces liability for investors, increases morale and engagement of employees, creates an environmentally cleaner community, and enhances the partnership with all of its stakeholders.

CR 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. APUC has environmentally supportive 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. The economic branch of the Corporation's CR efforts incorporates local spending, local hiring, and operational efficiency. The Corporation's commitment to people is demonstrated through our employee training, learning and development programs, organizational improvements, emergency management, health and safety policies, diversity in the workplace, and community involvement. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments, and business partners.

## 3.10 Credit Ratings

APUC and its subsidiaries maintain the following credit ratings by the Rating Agencies [1]:

| | S&P | | DBRS | | Moody's | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 | 2016 | 2015 |
| APUC - Issuer rating | BBB | BBB | BBB(low) | BBB(low) | - | - |
| APUC - Preferred Shares | P-3 [3] | P-3 [3] | Pfd-3 (low) | Pfd-3 (low) | - | - |
| APCo - Issuer rating | BBB | BBB | BBB (low) | BBB (low) | - | - |
| APCo - Senior unsecured debt | BBB | BBB | BBB (low) | BBB (low) | - | - |
| Liberty Utilities | BBB | BBB | - | - | - | - |
| LU GP1 - Issuer rating [2] | - | - | BBB (high) | BBB (high) | - | - |
| LU GP1 - Senior unsecured notes | - | - | BBB (high) | BBB (high) | - | - |
| Empire - Issuer rating | BBB | BBB | - | - | Baa1 | Baa1 |
| Empire - First mortgage bonds | | | - | - | A2 | A2 |
| Empire - Senior unsecured debt | | | - | - | Baa1 | Baa1 |
| Empire - Commercial paper | | | - | - | P-2 | 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 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 LU Gp1 and guaranteed by Liberty Utilities.

[3] P-3 rating is equivalent to a BB rating on S&P's global preferred share rating scale

### S&P

Standard & Poor's ("S&P") rates debt instruments and issuers with ratings ranging from "AAA", which represent the greatest ability of an obligor to meet its financial commitment, to "D", which represents an obligor in payment default. 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 lead to a weakened capacity of the obligor to meet its financial commitments. An S&P rating 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.

According to the S&P rating system, preferred shares rated P-3 are regarded as having significant speculative characteristics. While such securities will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. The 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 Limited ("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 represent debt instruments for which a company has not made a scheduled payment of interest or principal or has made it clear it will miss such a payment in the near future. A rating of “BBB” by DBRS denotes an obligor having adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. A DBRS rating may be modified by the addition of a “(high)” or “(low)” to indicate the relative standing within a particular rating category. The absence of either a “(high)” or “(low)” designation indicates that the rating is in the “middle” of the category.

According to the DBRS rating system, 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.

Moody's

Moody's Investors Service, Inc. ("Moody's") rates debt instruments and issuers with ratings ranging from “Aaa”, which represent the greatest ability of an obligor to meet its financial commitment, to “C”, which represents an obligor in payment default. A rating of "A" by Moody's denotes obligations judged to be upper-medium grade and are subject to low credit risk, while a rating of "Baa" by Moody's denotes an obligations judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. A Moody's rating may be modified by the addition of a numerical modifiers 1, 2, and 3 to show relative standing within the major rating categories.

Short-term obligations of an issuer 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 "P-3", which represent an issuer's acceptable ability to repay short-term obligations.

# 4. ENTERPRISE RISK FACTORS

An enterprise risk management ("ERM") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC’s ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

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

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

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

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

## 4.1 Treasury Risk Factors

### 4.1.1 Downgrade in the Corporation's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. APCo has a BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing entity of Liberty Utilities Co has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's.

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

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

### 4.1.2 Liquidity Risk

As of December 31, 2016, the Corporation had approximately $3,913.4 million of consolidated indebtedness. Management of the Corporation believes, based on its current expectations as to the Corporation’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 Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management’s expectations as to future performance will be

realized.

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

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

The ability of the Corporation 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 Corporation, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and future capital expenditure requirements. In addition, the ability of the Corporation 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. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Corporation 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 outstanding indebtedness or to fund any other liquidity needs.

### 4.1.3 Tax Risk and Uncertainty

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

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

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

### 4.1.4 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 Corporation.

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

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

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

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

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

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

### 4.1.5 Foreign Currency Risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 84% of EBITDA in 2016 and 83% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $40.0 million ($0.16 per share) on an annual basis.In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs. Although APUC may enter into derivative contracts to hedge currency exchange rate exposure, the Corporation typically does not hedge its full exposure. To the extent that the Corporation does enter into currency hedges, the Corporation will not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts

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

### 4.1.6 Market Price Risk

The Renewable Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the

Renewable Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Corporation 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 Corporation to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Renewable Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Renewable Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

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

On May 15, 2012, the Renewable Generation Group entered into a financial hedge, which expired December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge was structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. Starting in 2017, the unhedged production based on long term projected averages is approximately 65,000 MW-hrs annually. Therefore, each U.S. $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. $0.7 million on an annualized basis.

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

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

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 million for the year.

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

In addition to the above noted hedges, from time to time the Renewable Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2016, the Renewable Generation Group had not entered into any such short-term derivative contracts.

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

### 4.1.7 Commodity Price Risk

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

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.

- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 164,000 MW-hrs in fiscal 2017, of which 133,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 25,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 164,000 MW-hrs. The risk associated with the expected market purchases of 25,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 78% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $83 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.1 million on an annualized basis.

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

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

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

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

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

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

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

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

### 4.1.8 Defined Benefit Pension Plan Risk

In conjunction with certain utilities acquisitions, the Corporation assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity, gas and water utilities are non-contributory defined pension plans covering all eligible legacy and union employees of the acquired businesses. Benefits are generally based on each employee's years of service and compensation. The Corporation also provides a defined benefit cash balance pension plan covering new employees, transitioned employees and certain legacy employees under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and, in some cases, 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.

APUC engages professional investment managers to manage the investments under prescribed investment policies and procedures in respect of permitted investments and asset allocations. Future contributions to the APUC'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, APUC could be required to make contributions to its Plans in excess of those currently expected.

### 4.1.9 Substantial Indebtedness Relating to the Empire Acquisition

*APUC substantially increased its amount of indebtedness following the Empire Acquisition*

As part of the Empire Acquisition, APUC assumed all of Empire's existing debt. As a result, APUC substantially increased its amount of indebtedness upon the Empire Acquisition and such increased indebtedness may adversely affect APUC's cash flow and ability to operate its business.

*The Empire Acquisition and related financing, including the Offering, could result in a downgrade of the credit rating of APUC, Empire and/or their subsidiaries*

The change in the capital structure of APUC as a result of the Empire Acquisition, and the entering into of the Empire Acquisition Credit Facilities could cause credit rating agencies which rate the outstanding debt obligations of APUC to re-evaluate and potentially downgrade the Corporation's current credit ratings, which could increase the Corporation's borrowing costs.

The Empire Acquisition could also result in a downgrade of the credit ratings of Empire and The Empire District Gas Company as well as significant mandatory redemptions of five outstanding series of bonds if the credit rating of either company, or of APUC as the acquirer, falls below "BB+" or lower by S&P or "Ba1" or lower by Moody's.

Should such an event occur, Empire must make an offer to purchase all of the outstanding Empire bonds. To the extent that such offer is accepted, the bonds must be purchased at 100% of the principal amount, together with accrued and unpaid interest.

#### 4.1.10 Interest Rate Risk

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

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

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

## 4.2 Operational Risk Factors

### 4.2.1 Mechanical and Operational Risks

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

The Renewable Generation Group's hydro assets utilize dams to pond water for generation and if the dam fail, 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 programs to reduce the likelihood of dam failure.

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

The Renewable Generation Group's Thermal Energy Division uses natural gas and oil, and produce exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could reduce 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 somewhat by long term purchases.

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

The 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, 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.

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, maintaining adequate insurance and an active Enterprise Risk Management program.

### 4.2.2 Development and Construction Risk

The Corporation 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 Corporation'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 Corporation's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

The Corporation mitigates these risk through its due diligence processes, sound project management practices, formal risk management processes and appropriate contingency plans.

*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 Corporation 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.

### 4.2.3 Cycles and Seasonality Risk

Please see "*Description of the Business – Cycles and Seasonality*" for a detailed description and discussion of this risk.

### 4.2.4 Energy Efficiency Risk

Regulatory and legislative bodies have proposed requirements and incentives 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.

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 Renewable Generation Group can sell wholesale electric power.

Increased adoption of these practices would not materially decrease the operating costs and capital expenditure requirements for the Liberty Utilities Group's electric distribution systems but, in the case of self-generation, may decrease the pool of customers from whom fixed costs would be recovered. If the Liberty Utilities Group were unable to adjust its electric distribution rates to reflect the reduced electricity demand, the Corporation's business, financial condition and results of operations could be adversely affected.

### 4.2.5 Cyber Security

APUC relies upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions, and the invoicing and collection of payments from the Corporation's customers. APUC also use 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. APUC's technology networks and systems collect and store sensitive data including system operating information, proprietary business information belonging to APUC and third parties, and personal information belonging to the Corporation's customers and employees.

APUC's information technology networks and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, or other disruptions during software or hardware upgrades, telecommunication failures or natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of APUC's generation, transmission and distribution systems; could expose the Corporation, its customers or 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 its reputation or otherwise harm the business. APUC cannot accurately assess the probability that a security breach may occur, despite the measures that APUC takes to prevent such a breach, and the Corporation is unable to quantify the potential impact of such an event. APUC can provide no assurance that the Corporation or any of its subsidiaries will identify and remedy all security or system vulnerabilities or that unauthorized access or error will be identified and remedied.

Additionally, APUC cannot predict the impact that any future information technology or terrorist attack may have on the energy industry in general. APUC's facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to APUC's generation, transmission and distribution systems or to the electrical grid in general, and could increase the cost of insurance coverage or result in a decline in the U.S. or Canadian economies.

### 4.2.6 Environmental Risks

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 for both new and existing facilities. Although the Liberty Utilities Group

historically has 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 Renewable Generation 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 result in a material adverse effect on the Corporation's business, financial condition and results of operations.

The Corporation and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation, and utilities business segments, which have the potential to become environmental liabilities. Certain environmental risks associated with the Corporation's operations include uncontrolled natural gas or contaminant releases (or releases above the permitted limits), 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 resulting from wildlife mortality monitoring, and dam safety.

In addition, like other industrial companies, 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 Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of the Liberty Utilities Group, these costs are often allowed in rate case proceedings to be recovered from customers over a specified period.

### 4.2.7 Asset Retirement Obligations

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

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

In conjunction with acquisitions and developed projects, the Corporation assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

### 4.2.8 Dependence Upon Key Customers

A substantial portion of the output of the Renewable Generation Groups power generation facilities is sold under long-term power purchase agreements, 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 of any such power purchase agreement, unless replaced on equally favorable terms, would increase the Corporation's exposure to wholesale power market price risk, which could have an adverse effect on the business, financial condition and results of operations of the Corporation.

### 4.2.9 Personnel and Labour

The Corporation's operations depend on the continued efforts of its employees. 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, such as an aging workforce, 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.

While labor relations have been stable to date and there have not been any disruptions in operations as a result of labor disputes with employees, the maintenance of a productive and efficient labor environment without disruptions cannot be assured. In the event of a strike, work stoppage or other form of labor disruption, the Corporation would be responsible for procuring replacement labor and could experience disruptions in its utility operations.

### 4.2.10 Obligations to Serve

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

### 4.2.8 Litigation risks and other contingencies

Please see "*Legal Proceedings and Regulatory Actions - Part 9. Legal Proceedings and Regulatory Actions* " for a detailed description and discussion of this risk.

## 4.3 Regulatory Climate and Permitting Risks

### 4.3.1 Regulatory Climates

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

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

### 4.3.2 Health and Safety Laws

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 citing, construction, operation and decommissioning of wind 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 us 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.

### 4.3 Condemnation Expropriation Proceedings

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 is no assurance as to the value that would be received for those assets, including that the value received would be above book value or that the Corporation would not recognize a loss.

## 4.4 Acquisitions and Divestitures

Acquisitions of complementary businesses and technologies are a part of APUC's overall business strategy. In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into APUC's business or service offerings. .Acquisition risks also include delays in implementation, failure to realize operating benefits or synergies from completed transactions, assumption or incurrence of unexpected costs or liabilities, negative impacts on liquidity or credit ratings, and failure to retain key personnel, among others.

Similarly, divestitures of businesses that are no longer viewed as being strategic to APUC's continuing operations can be an active part of APUC's overall business strategy. Divestitures may result in a reduction in total revenues and net income.

APCo and Liberty Utilities each have a transition management office ("TMO") that has developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes promote the effective organization of people, resources and time frames for a successful integration of technology, operations, asset management and business processes. The TMO uses a sound governance reporting structure which includes the participation of the senior management of the Renewable Generation Group and the Liberty Utilities Group to ensure that the respective operations and processes are implemented in a timely and efficient manner. The governance process also includes a transparent issue resolution process which is documented and reported throughout the Renewable Generation Group and the Liberty Utilities Group.

### 4.4.1 Failure to Realize Intended Benefits

In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into the Corporation's business or service offerings, and that expected operating benefits or synergies from completed transactions will not be realized. In addition, the Corporation may incur unexpected costs or liabilities in connection with any acquisition.

The success of an acquisition may depend on retention of the workforce or key employees of the acquired business. Although in such cases the Corporation undertakes efforts to retain employees of the acquired business and includes the estimated cost of retention in its decision-making with respect to the acquisition, the accuracy of such estimates and success of such efforts cannot be assured.

The Corporation seeks to avoid unexpected liabilities through the conduct of its due diligence investigation of the target business and through contractual remedies for material misrepresentations in the acquisition agreement. However, detailed information regarding the target 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. There may be liabilities of the target that the Corporation failed to discover or was unable to quantify in the due diligence conducted prior to closing an acquisition. The discovery or quantification of any material liabilities of a target could have a material adverse effect on the Corporation's business, financial condition, results of operations or future prospects, as the Corporation may partially or fully bear the risk for any inaccuracies in the information, representations or warranties provided by an acquired target entity.

### 4.4.2 Integration Risks

Although management believes that post-closing an acquisition of the Corporation will provide benefits to the Corporation, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. The challenge of combining previously independent businesses makes evaluating the Corporation's business and future financial prospects difficult. The past financial performance of the Corporation may not be indicative of its future financial performance.

Failure to realize the anticipated benefits of an acquisition may impact the financial performance of the Corporation, the price of its Common Shares and the ability of APUC to continue to pay dividends on its Common Shares at current rates or

at all. The declaration of dividends by the Corporation is at the discretion of the Board and the Board may determine at any time to cease paying dividends.

### 4.4.3 Demands on Management and Operating Systems

The pursuit and completion of acquisitions place significant demands on the Corporation's managerial, operational and financial personnel and systems. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from completed acquisitions. The Corporation'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 effective operational and financial controls and reporting systems.

### 4.4.4 Divesting at a Loss

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. Although the Corporation seeks to maximize the price obtained for any such business or assets, the Corporation may recognize a loss upon such a sale. In addition, divestitures may result in a reduction in total revenues and net income.

## 5. DIVIDENDS

*Common Shares*

The total amount of dividends declared on the Common Shares for fiscal 2014, 2015, and 2016 were $82.9 million, $124.8 million, and $149.2 million respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2014, 2015 and 2016 were $0.37, $0.49, and $0.55 respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. On January 16, 2017, the Board approved a dividend increase of U.S. $0.0424 per common share annually, bringing the total annual dividend to U.S. $0.4659 per common share, an increase of 10% over the previous annual dividend rate.

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. See "Enterprise Risk Factors".

*Preferred Shares*

On November 9, 2012, APUC issued 4,800,000 Series A Shares (the "Series A Shares"). For an initial six year period the 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 at an annual rate equal to $1.1250 per Series A Share. In each of 2014, 2015 and 2016, dividends paid to Series A Shareholders totalled $5.4 million per year.

On January 1, 2013, the Corporation issued 100 redeemable Series C Shares and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by the Senior Management. The Series C Shares provide dividends essentially identical to that expected from the Class B units. In 2014, 2015 and 2016, dividends paid to Series C preferred shareholders were $0.9 million, $0.9 million and $0.9 million, respectively.

On March 5, 2014, APUC issued 4,000,000 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 $1.250 per Series D Share. In 2014, 2015, and 2016, dividends paid to Series D Shareholders totalled $4.1 million, $5.0 million and $5.0 million, respectively.

### 5.1 Dividend Reinvestment Plan

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the " **Reinvestment Plan**") which is offered to registered holders of Common Shares.

The purpose of the Reinvestment Plan is to enable Shareholders to invest cash dividends paid on Common Shares in additional Common Shares ("**Plan Shares**"). All such Plan Shares will be, at APUC's election, either (i) Common Shares purchased on the open market through the facilities of the TSX ("**Market Purchase**") or (ii) newly issued Common Shares purchased from treasury (" **Treasury Purchase**").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the

agent for all Plan Shares purchased in respect of a dividend payment date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Common Shares on the TSX for the five trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by shareholders in connection with the Reinvestment Plan.

As at December 31, 2016, 61,419,484 Common Shares had been registered with the Reinvestment Plan.

# 6. DESCRIPTION OF CAPITAL STRUCTURE

## 6.1 Common Shares

The Common Shares are publicly traded on the Toronto Stock Exchange (" **TSX**") and the New York Stock Exchange (" **NYSE**"). During the fourth quarter APUC received approval to list its commons shares for trading on the NYSE under the ticker symbol "**AQN**". The Corporation has been a U.S. Securities and Exchange Commission ("**SEC**") registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the TSX also under the ticker symbol "**AQN**".

As at December 31, 2016, APUC had 274,087,018 issued and outstanding Common Shares.

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

## 6.2 Private Placements of Subscription Receipts and Common Shares to Emera

Until 2016, Emera was the largest shareholder of APUC. In 2016, Emera disposed of 100% of its interests in APUC with a sale on May 24, 2016 of 50,126,766 Common Shares and a sale on December 8, 2016 of 12,938,457 Common Shares. Consequently, as at March 10, 2017, Emera owns no Common Shares. The strategic investment agreement with Emera was terminated on January 13, 2017.

*Common Shares*

For the year ended December 31, 2016, APUC issued a total of 12,938,457 Common Shares for proceeds of $110.5 million pursuant to the conversion of subscription receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- On December 29, 2014, the Corporation received total proceeds of $77.5 million from the issuance to Emera of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo investment. Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 661,693 additional common shares in lieu of dividends declared during the holding period
- On December 29, 2014, the Corporation received total proceeds of $33.0 million from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition. Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 252,011 additional common shares in lieu of dividends declared during the holding period.

For the year ended December 31, 2015, APUC did not issue any Common Shares to Emera.

For the year ended December 31, 2014, APUC did not issue any Common Shares to Emera.

## 6.3 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, 2016, APUC had outstanding:

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

On November 9, 2012, APUC issued 4.8 million Series A Shares at a price of $25 per share, for aggregate gross proceeds of $120 million. The Series A Shares yield 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The Series A Shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering were used primarily to partially fund the acquisition of the U.S Wind Portfolio interests which closed on December 10, 2012. The Series A Shares are convertible in certain circumstances into cumulative floating rate preferred shares, Series B (the "**Series B Shares**").

On January 1, 2013, APUC issued an aggregate of 100 Series C Shares to the holders of the Class B units of St. Leon LP, in exchange for such Class B units.

On March 5, 2014, APUC issued 4.0 million Series D Shares at a price of $25 per share, for aggregate gross proceeds of $100 million. The Series D Shares yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities and for general corporate purposes. The Series D Shares are convertible in certain circumstances into cumulative floating rate preferred shares, Series E (the "**Series E Shares**").

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 the Corporation shall have failed to pay eight quarterly dividends on such shares. The terms of the outstanding preferred shares do not contain a right to participate in a take-over bid of the Common Shares of the Corporation.

As at December 31, 2016, APUC had 4.8 million Series A Shares, 100 Series C Shares, and 4.0 million Series D Shares outstanding.

## 6.4 Convertible Debentures

### 6.4.1 Convertible Unsecured Subordinated Debentures

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

The Debentures will mature on March 31, 2026. The Debentures accrued interest at an annual rate of 5% per $1,000 dollars principal amount of Debentures until and including the Final Instalment Date, after which the interest rate became 0%.

At the option of the holders and provided that payment of the Final Installment has been made, each Debenture is convertible into Common Shares of the Corporation at any time prior to the earlier of maturity or redemption by the Corporation, at a conversion price of $10.60 per Common Share.

The Final Instalment Date took place on February 2, 2017. The proceeds received from the Final Instalment was $767.1 million before financing costs of $23.0 million. Holders of the Debentures who paid the Final Instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017. Based on the first instalment of $333 per $1,000 principal amount of the Debentures and the make-whole payment, the effective annual yield to and including the Final Instalment Date was 16.4%.

APUC will issue up to 108,490,566 common shares on conversion of all of the Debentures. As at March 1, 2017, a total of 107,517,895 common shares of the company were issued, representing conversion into common shares of more than 99.1% of the Debentures. Debentures not converted may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. At maturity, the Corporation will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

## 6.5 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. For employees resident in Canada, APUC will match up to 20% of an employee’s contribution amount for the first $5,000 contributed annually and 10% of an employee’s contribution amount for contributions over $5,000 and up to $10,000 annually. For employees resident in the United States, APUC will match 15% of an employee's contribution amount up to $10,000 annually. 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 APUC’s option, the shares may be (i) issued to participants from treasury at the weighted average share price at the time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the year, the Corporation issued 144,264 Common Shares to employees under the ESPP plan.

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

## 6.6 Directors Deferred Share Units

APUC has a deferred share unit plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units (“**DSUs**”) in lieu of cash compensation. Up to 1,000,000 common shares may be issued from treasury under the plan. 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 Corporation’s Common Share. 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 APUC. As APUC does not expect to settle the DSU’s in cash, these DSUs are accounted for as equity awards.

During the twelve months ended December 31, 2016 , the Corporation issued 67,192 DSUs to the directors of the Corporation.

As at December 31, 2016, a total of 224,663 DSUs had been granted under the DSU plan.

## 6.7 Performance Share Units

APUC issues performance share units ("**PSUs**") to its employees as part of APUC'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 based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 0% to 197.5% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire.

The plan provides for settlement in cash or shares at the election of the Corporation. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Corporation expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

During the twelve months ended December 31, 2016 , the Corporation granted (including dividends) 219,315 PSUs to executives and employees of the Corporation. During the year the Corporation settled 181,875 PSU by issuing 91,280 shares from treasury, with the balance withheld as payment in lieu of minimum tax withholdings.

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

## 6.8 Shareholders' Rights Plan

The shareholders' rights plan (the " **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. An amended and restated rights plan (the "**Amended and Restated Rights Plan**") was approved by shareholders at the annual and special meeting of shareholders of APUC held in 2016.

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 twenty percent or more of the outstanding Common Shares without complying with the permitted bid provisions of the Plan. The application of the Rights Plan to acquisition of Common Shares by Emera under allowed transactions was waived following shareholder approval at the annual and special meeting of shareholders held on June 21, 2010. 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 fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the 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 fifty percent 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 ten days to allow all other shareholders to tender.

At the annual and special shareholders' meeting held on June 9, 2016, the shareholders of APUC approved an amendment to and the continuance of the Rights Plan. The amendments to the Rights Plan included:

- amending the definition of Permitted Bid to be outstanding for a minimum period of 105 days or such shorter period that a take-over bid must remain open for deposits of securities, in the applicable circumstances, pursuant to Canadian securities laws; and
- certain additional non-substantive, technical and administrative amendments, including to align the definition of a Competing Permitted Bid to the minimum number of days as required under Canadian securities laws.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2019 or its termination under the terms of the of Amended and Restated Rights Plan. The Amended and Restated Rights Plan is similar to rights plans adopted by many other Canadian corporations.

## 6.9 Stock Option Plan

The Corporation implemented a stock option plan (the "**Stock Option Plan**") in 2010. The purpose of the Stock Option Plan is to attract, retain and motivate persons as key service providers to the Corporation and its affiliates and to advance the interests of the Corporation by providing such persons with the opportunity, through stock options ("**Options**"), to acquire a proprietary interest in the Corporation.

The Stock Option Plan authorizes the Board to issue Options to directors, officers or employees of the Corporation or any affiliate (an " **Eligible Individual**"), a corporation controlled by an Eligible Individual or any person/company, partnership, trust or corporation engaged to provide management or consulting services for the Corporation or any affiliate ("**Eligible Persons**").

The aggregate number of Common Shares that may be reserved for issuance under the Stock Option Plan must not exceed 8% of the number of Common Shares outstanding at the time the Options are granted, less the Common Shares issuable under grants under all other securities-based compensation plans. For greater clarity, the Stock Option Plan is "reloading" in the sense that, to the extent that Options expire or are terminated, cancelled or exercised, the Corporation may make a further grant of Options in replacement for such expired, terminated, cancelled or exercised Options, provided that the 8% maximum is not exceeded. No fractional Common Shares may be purchased or issued under the Stock Option Plan.

In addition, under the Stock Option Plan:

- subject to the terms of the Stock Option Plan, the number of Common Shares subject to each Option, the exercise price of each Option, the expiration date of each Option, the extent to which each Option vests and is exercisable from time to time during the term of the Option and other terms and conditions relating to each Option will be determined by the Board from time to time;
- subject to any adjustments pursuant to the provisions of the Stock Option Plan, the exercise price of any Option shall in no circumstances be lower than the Market Price (as defined below) of the Common Shares on the date on which the Board approves the grant of the Option;
- Options will be personal to the grantee and will be non-transferable and non-assignable, except in certain limited circumstances;
- the maximum number of Common Shares which may be reserved for issuance to insiders under the Stock Option Plan, together with the number of Common Shares reserved for issuance to insiders under any other securities based compensation arrangement, shall be 10% of the Common Shares outstanding at the time of the grant;
- the maximum number of Common Shares which may be issued to insiders under the Stock Option Plan and all other security based compensation arrangements within a one year period shall be 10%of the Common Shares outstanding at the time of the issuance;
- non-employee director participation in the Stock Option Plan is limited to the lesser of (i) a reserve of 1% of the Common Shares outstanding for non-employee directors as a group and (ii) an annual equity award value of $100,000 per director;
- if the expiration date for an Option occurs during a Blackout Period (as defined below) or within 10 business days after the expiry date of a Blackout Period applicable to a person granted Options (an "**Optionee**"), then the expiration date for that option will be extended to the 10th business day after the expiry date of the Blackout Period. A "**Blackout Period**" is a period of time of time during which the Optionee cannot exercise an Option, or sell Common Shares issuable pursuant to the exercise of Options, due to applicable policies of the Corporation in respect of insider trading); and
- except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

Under the Stock Option Plan, "**Market Price**" of the Common Shares is defined as the volume weighted average trading price of such Common Shares on the TSX (or, if such Common Shares are not then listed and posted for trading on the TSX, on such stock exchange in Canada on which such Common Shares are listed and posted for trading as may be selected for such purpose by the Board) for the five consecutive trading days immediately preceding such date, provided that in the event that such Common Shares did not trade on any of such trading days, the Market Price will be the average of the bid and ask prices in respect of such Common Shares at the close of trading on all of such trading days and provided that in the event that such Common Shares are not listed and posted for trading on any stock exchange, the Market Price will be the fair market value of such Common Shares as determined by the Board in its sole discretion.

The Stock Option Plan provides that, except as set out in the Stock Option Plan or any resolution passed at any time by the Board or the terms of any option agreement or employment agreement with respect to any Option or an Optionee, an Option and all rights to purchase Common Shares pursuant thereto shall expire and terminate immediately upon the Optionee who holds such Option ceasing to be an Eligible Person.

Where an Optionee (other than a service provider) resigns from the Corporation or is terminated by the Corporation for cause, the Optionee's unvested Options shall immediately be forfeited and the Optionee's vested Options may be exercised for a period of 30 days after the date of resignation or termination.

Where an Optionee (other than a service provider) retires from the Corporation or ceases to serve the Corporation or an affiliate as a director, officer or employee for any reason other than a termination by the Corporation for cause, the Optionee's unvested

Options may be exercised within 90 days after such retirement or termination. The Board may in such circumstances accelerate the vesting of unvested Options then held by the Optionee at the Board's discretion.

In the event that an Optionee, other than a service provider, has suffered a permanent disability, Options previously granted to such Optionee shall continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Stock Option Plan, but no additional grants of Options may be made to the Optionee.

If an Optionee, other than a service provider, dies, all unexercised Options held by such Optionee at the time of death immediately vest, and such Optionee's personal representatives or heirs may exercise all Options within one year after the date of such death.

All Options granted to service providers shall terminate in accordance with the terms, conditions and provisions of the associated option agreement between the Corporation and such service providers, provided that such termination shall occur no later than the earlier of (i) the original expiry date of the term of the Option and (ii) one year following the date of termination of the engagement of the service provider.

Options may be exercised in accordance with the specific terms of their grant and by the Optionee delivering the exercise price to the Corporation for all of the Options exercised. The Optionee may also surrender Options and receive in exchange for each such Option, the amount by which the Market Price of the Common Shares exceeds the exercise price of the Option (the "**In-the-Money Amount**"). If the Optionee elects to surrender any Options in exchange for the In-the-Money Amount, the Corporation will determine whether to pay such amount in cash or in Common Shares representing the equivalent of the In-the-Money Amount based on the Market Price of the Common Shares at the date of exercise, in each case net of an amount equal to any withholding taxes.

In the event that the Common Shares are at any time changed or affected as a result of the declaration of a stock dividend, a Common Share subdivision or consolidation, the number of Common Shares reserved for Options shall be adjusted accordingly by the Board to such extent as it deems proper in its discretion.

If, after the grant of an Option and prior to its expiry:

(i) the Common Shares are reclassified, reorganized or otherwise changed (a " **Share Reorganization**"), otherwise than as specified in the immediately preceding paragraph, or

(ii) subject to the Corporation's right to allow the exercise of vested and unvested Options following the occurrence of certain transactions, the Corporation shall consolidate, merge or amalgamate with or into another corporation (a "**Merger**", with the resulting corporation being the "**Successor Corporation**"),

the Optionee will receive, upon the subsequent exercise of his or her Options in accordance with the Stock Option Plan, the number of Common Shares or securities of the appropriate class of the Corporation or Successor Corporation, as the case may be, that the Optionee would have received if on the record date of such Share Reorganization or Merger the Optionee were the registered holder of the number of Common Shares to which the Optionee was prior thereto entitled to receive on exercise of his or her Options.

The Board may amend, suspend or discontinue the Stock Option Plan or amend Options granted under the Stock Option Plan at any time without shareholder approval; provided, however, that:

(a) approval by a majority of the votes cast by shareholders present and voting in person or by proxy at a meeting of shareholders of the Corporation shall be obtained for the following amendments:

  (i) any amendment for which, under the requirements of the TSX or any applicable law, shareholder approval is required;

  (ii) reduction of the exercise price, or cancellation and reissuance of Options or other entitlements, of non-insider Options granted under the Stock Option Plan;

  (iii) extension of the term of Options beyond the original expiry date of non-insider Options;

  (iv) change in Eligible Participants that may permit an increase to the limit imposed on non-employee director participation;

  (v) permitting of Options granted under the Stock Option Plan to be transferable or assignable other than for estate settlement purposes; or

  (vi) amendment to the Stock Option Plan's amendment provisions; and

(b) the consent of the Optionee is obtained for any amendment which alters or impairs any Option previously granted to an Optionee under the Stock Option Plan.

Notwithstanding the other provisions of the Stock Option Plan, if:

(a) the Corporation proposes to amalgamate, merge or consolidate with any other corporation (other than a wholly-owned affiliate) or to liquidate, dissolve or wind-up;

(b) an offer to purchase or repurchase all of the Common Shares shall be made to all holders of Common Shares which offer has been approved or accepted by the Board; or

(c) the Corporation proposes the sale of all or substantially all of the assets of the Corporation as an entirety, or substantially as an entirety, so that the Corporation shall cease to operate any active business,

then, the Corporation will have the right, upon written notice thereof to Optionees, to permit the exercise of all such Options, whether or not vested, within the 20 day period next following the date of such notice and to determine that upon the expiration of such 20 day period, all rights of the Optionee to such Options or to exercise same (to the extent not theretofore exercised) shall *ipso facto* terminate and cease to have further force or effect whatsoever.

In 2016, the shareholders of APUC approved a provision whereby in the event that the Corporation 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 Corporation's clawback policy.

During the twelve months ended December 31, 2016 , the Corporation granted 2,596,025 options to executives of the Corporation. The options allow for the purchase of common shares at a weighted average price of $10.85, the market price of the underlying common share at the date of grant. In March 2016, executives of the Corporation exercised 3,715,663 stock options at a weighted average exercise price of $5.25 in exchange for 2,720,980 common shares issued from treasury and 994,683 shares withheld as payment in lieu of minimum tax withholdings.

As at December 31, 2016, a total of 6,045,014 options are issued and outstanding under the plan.

# 7. MARKET FOR SECURITIES

## 7.1 Trading Price and Volume

### 7.1.1 Common Shares

APUC's 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[1] | | |
|---|---|---|---|---|---|---|
| 2016 | High ($) | Low ($) | Volume | High (US$) | Low (US$) | Volume |
| January | 11.61 | 10.30 | 18,306,398 | - | - | - |
| February | 12.01 | 10.35 | 19,956,511 | - | - | - |
| March | 11.07 | 10.30 | 25,928,607 | - | - | - |
| April | 10.97 | 10.58 | 12,093,465 | - | - | - |
| May | 11.68 | 10.90 | 30,140,298 | - | - | - |
| June | 12.05 | 11.46 | 23,325,423 | - | - | - |
| July | 12.45 | 11.97 | 11,339,436 | - | - | - |
| August | 12.31 | 11.70 | 14,095,412 | - | - | - |
| September | 12.14 | 11.65 | 16,341,635 | - | - | - |
| October | 11.98 | 11.30 | 20,548,145 | - | - | - |
| November | 11.89 | 10.47 | 34,480,689 | 8.58 | 7.94 | 51,403 |
| December | 11.61 | 10.88 | 22,690,585 | 8.90 | 8.20 | 175,236 |

1. Common shares commenced trading on the NYSE on November 29, 2016

### 7.1.2 Preferred Shares

*Series A Shares*

APUC's Series A Shares became listed and commenced trading on the TSX under the symbol "AQN.PR.A" on November 9, 2012.

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).

| 2016 | High ($) | Low ($) | Volume |
|---|---|---|---|
| January | 17.55 | 14.10 | 60,202 |
| February | 15.83 | 13.42 | 81,570 |
| March | 15.85 | 13.79 | 83,092 |
| April | 16.85 | 15.30 | 55,776 |
| May | 16.80 | 16.32 | 69,234 |
| June | 17.60 | 16.16 | 60,369 |
| July | 17.56 | 16.23 | 179,782 |
| August | 18.67 | 16.90 | 267,718 |
| September | 18.44 | 17.53 | 38,233 |
| October | 19.06 | 18.12 | 313,235 |
| November | 19.61 | 18.32 | 170,274 |
| December | 20.08 | 18.59 | 64,878 |

*Series D Shares*

APUC's Series D Shares became listed and commenced trading on the TSX under the symbol "AQN.PR.D" on March 5, 2014.

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).

| 2016 | High ($) | Low ($) | Volume |
|---|---|---|---|
| January | 21.55 | 17.23 | 39,157 |
| February | 18.93 | 15.81 | 47,574 |
| March | 18.65 | 16.39 | 77,698 |
| April | 18.84 | 17.75 | 155,681 |
| May | 18.65 | 17.34 | 80,505 |
| June | 19.25 | 17.98 | 73,990 |
| July | 19.23 | 18.30 | 61,300 |
| August | 20.98 | 19.08 | 38,941 |
| September | 20.60 | 19.45 | 46,192 |
| October | 21.05 | 20.01 | 215,192 |
| November | 21.96 | 20.75 | 61,883 |
| December | 22.96 | 21.10 | 73,492 |

## 7.2 Prior Sales

During the year ended December 31, 2010, 1,160,205 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $4.05 per share. One-third of the Options vested on each of January 1, 2011, 2012 and 2013.

During the year ended December 31, 2011, the Board approved the following grant of Options:

- On March 22, 2011, 892,107 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $5.23 per share;
- On June 21, 2011, 171,642 Options were granted to a senior executive of APCo which allow for the purchase of Common Shares at a price of $5.64 per share;
- On July 28, 2011, 90,909 Options were granted to a senior executive of APUC which allow for the purchase of Common Shares at a price of $5.74 per share; and
- On September 13, 2011, 172,242 Options were granted to a senior executive of Liberty Utilities which allow for the purchase of Common Shares at a price of $5.65 per share.

In each case, one-third of the Options vested on each of January 1, 2012, 2013, and 2014.

On March 14, 2012, 1,194,606 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $6.22 per share. One-third of the Options vest on each of January 1, 2013, 2014 and 2015.

On June 19, 2012, 69,016 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $6.56 per share. One-third of the Options vest on each of January 1, 2013, 2014 and 2015.

On March 14, 2013, 816,402 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $7.72 per share. One-third of the Options vest on each of January 1, 2014, 2015, and 2016.

On May 13, 2014, 969,998 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $7.95 per share. One-third of the Options vest on each of January 1, 2015, 2016, and 2017.

On May 19, 2015, 1,608,974 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $9.76 per share. On August 27, 2015, 18,551 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $9.23 per share. One-third of the Options vest on each of January 1, 2016, 2017, and 2018.

On March 31, 2016, 2,487,601 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $10.82 per share. On June 12th, 2016, 108,424 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $11.59 per share. One-third of the Options vest on each of January 1, 2017, 2018, and 2019.

All Options were issued using the five day volume weighted average price of the underlying Common Shares at the date of the grant. In all cases, Options may be exercised up to eight years following the date of grant. See the table below for a summary of options granted and exercised during the year ended December 31, 2016 and the balance of options issued and outstanding and exercisable as at December 31, 2016.

| | Number of shares | Weighted average exercise price | Weighted average remaining contractual term |
|---|---|---|---|
| Balance at December 31, 2015 | 7,164,652 | $ 6.92 | 4.74 |
| Granted | 2,596,025 | 10.85 | 8.00 |
| Exercised | (3,715,663) | 5.25 | 2.06 |
| Balance at December 31, 2016 | 6,045,014 | $ 9.64 | 6.27 |
| Exercisable at December 31, 2016 | 2,120,539 | $ 8.36 | 5.16 |

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

There are no securities of APUC that are 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 APCo and APUC. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| CHRISTOPHER J. BALL<br>Toronto, Ontario, Canada<br>Age: 66 | Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are investment banking boutique 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, and is a recipient of the Clean Energy BC Lifetime Achievement Award. | Director of APUC since October 27, 2009.<br>Trustee of APCo since October 22, 2002 |
| LINDA BEAIRSTO<br>Oakville, Ontario, Canada<br>Age: 56 | Ms. Beairsto is the Chief Compliance Officer and previously was the Chief General Counsel and Corporate Secretary for APUC from June 2011 to February 6, 2017. Prior to joining APUC, she held various diverse roles including Commercial Real Estate Lawyer at Fasken Martineau, Special Counsel at E.I. du Pont Canada Inc., Director of Legal Services at Patheon Inc., EVP & Chief Legal Counsel at ABC Group of Companies and Special Counsel at Allergan Inc. Ms. Beairsto earned a Bachelor of Arts Degree from the University of British Columbia and a Bachelor of Laws Degree from the University of New Brunswick. She was called to the Ontario Bar in 1990. She was awarded a Chartered Director (C.Dir) designation from McMaster University, De Groote School of Business as well as a Certified Compliance & Ethics Professional (CCEP)® designation from the Compliance Certification Board. | Officer of APUC since June 6, 2011 |
| DAVID BRONICHESKI<br>Oakville, Ontario, Canada<br>Age: 57 | Mr. Bronicheski is the Chief Financial Officer ("**CFO**") 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 HUSKILSON<br>Wellington, Nova Scotia, Canada<br>Age: 59 | Christopher Huskilson has been the President and Chief Executive Officer of Emera, a North American energy and services company, since November 2004. He is also Chair of Emera Maine, a Director of Nova Scotia Power Inc. and serves as the Chair or as a Director of a number of other Emera affiliated companies. Mr. Huskilson has held a number of positions within Nova Scotia Power Inc. and its predecessor, Nova Scotia Power Corporation, since June 1980. Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick. | Director of APUC since October 27, 2009.<br>Trustee of APCo since July 27, 2009 |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| CHRISTOPHER K. JARRATT<br>Oakville, Ontario, Canada<br>Age: 58 | 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 2010, 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. In 2009, Mr. Jarratt completed the Chartered Director program of the Directors College (McMaster University) and holds the certification of Ch. Dr. (Chartered Director). In addition, Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award. | Director of APUC since June 23, 2010. |
| D. RANDY LANEY<br>Farmington, Arkansas, USA<br>Age: 62 | D. Randy Laney was most recently Chairman of the Board of Empire District Electric Company since 2009. He joined the Board of Empire in 2003 serving as the Non-Executive Vice Chairman of the Board from 2008 to 2009 and Non-Executive Chairman of the Board from April 23, 2009 until APUC's acquisition of Empire on January 1, 2017. 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 including 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 APUC Board. | Director of APUC since February 1, 2017 |
| KENNETH MOORE<br>Toronto, Ontario, Canada<br>Age: 58 | 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 has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director). | Director of APUC since October 27, 2009.<br>Trustee of APCo since December 18, 1998 |
| JEFF NORMAN<br>Burlington, Ontario, Canada<br>Age: 48 | Jeff Norman is the Chief Development Officer of the Corporation, 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 Algonquin Power Co. (APCo) in 2008. Since 2008 the business development team has secured over 1GW 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. | Officer of APUC since May 25, 2015 |
| DAVID PASIEKA<br>Oakville, Ontario, Canada<br>Age: 60 | David Pasieka is the Chief Operating Officer of APUC's Liberty Utilities Group. As Chief Operating Officer, Mr. Pasieka is focused on acquiring and managing a portfolio of regulated water, natural gas and electrical companies throughout the United States. The focus of the portfolio is in the distribution, transmission, and generation sectors. 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 Degree from the University of Waterloo, Masters of Business Administration from the Schulich School of Business –York University and a Chartered Director designation from McMaster University. | Officer of APUC since September 1, 2011 |
| IAN E. ROBERTSON<br>Oakville, Ontario, Canada<br>Age: 57 | Ian Robertson is the Chief Executive Officer of the Corporation. 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 over 23 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 has completed the Chartered Director program of the Directors College (McMaster University), as well as a Global Professional Master of Laws degree from the University of Toronto and has the certification of Ch. Dir. (Chartered Director). Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association. | Director of APUC since June 23, 2010. |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| MASHEED SAIDI<br>Dana Point, California, United States<br>Age: 62 | Masheed Saidi has over 30 years of operational and business leadership experience in the electric utility industry. Ms. Saidi is 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 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 (P.E.). | Director of APUC since June 18, 2014 |
| DILEK SAMIL<br>Las Vegas, Nevada, United States<br>Age: 61 | 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 |
| MIKE SNOW<br>Markham, Ontario, Canada<br>Age: 56 | Mike joined APUC in 2011 and serves as Chief Operating Officer of APUC's Renewable Generation Group. He is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mike has led both industrial and consumer organizations focused on growth and international operations in Mexico, South America, and Asia, while driving culture change and building strong leadership teams. Mike holds a Bachelor of Science Degree in Math from Dalhousie University, a Bachelor of Engineering Degree (Mechanical) from the Technical University of Nova Scotia, and a Masters of Business Administration from the Ivey School of Business - Western University. Mike received his Chartered Director designation from McMaster University in 2014 and sits on the Board of Governors of the University of Ontario Institute of Technology. | Officer of APUC since July 4, 2011 |
| MELISSA STAPLETON BARNES<br>Age: 48<br>Carmel, Indiana, United States of America | 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. Reporting directly to the CEO and Board of Directors, 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; Conference Board, Global Council on Business Conduct; Healthcare Businesswomen's Association, and is a Licensed Attorney with the Indiana State Bar. Other board positions include The Center for the Performing Arts (Vice Chair), Visit Indy, The Children's Museum, and The Great American Songbook. | Director of APUC since June 9, 2016 |
| GEORGE L. STEEVES<br>Aurora, Ontario, Canada<br>Age: 67 | George Steeves is the principal of True North Energy, an energy consulting firm specializing in the provision of technical and financial due diligence services for renewable energy projects. 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 the Professional Engineering designation in Ontario and British Columbia. Additionally he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director). | Director of APUC since October 27, 2009.<br>Trustee of APCo since September 8, 1997 |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| JENNIFER TINDALE<br>Campbellville, Ontario, Canada<br>Age: 45 | Jennifer Tindale is the Chief Legal Officer of the Corporation. 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<br>Age: 56 | George Trisic is the Chief Administrative Officer and Corporate Secretary for the Corporation, and 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 shared services for the Corporation including information technology, human resources, communications, legal, and procurement, and is a well-regarded team builder and business partner. His skill set includes leading multi-functional groups in finance, human resources, legal, and information technology in a senior role. Mr. Trisic earned a Bachelor of Law Degree from the University of Western Ontario in 1984. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of C.Dir (Chartered Director). | 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 (the "**By-Laws**").

As at February 28, 2017, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,539,467 Common Shares, representing less than one percent of the total number of Common Shares outstanding before giving effect to the exercise of Options or warrants to purchase Common Shares held by such directors and executive officers. The statement as to the number of Common Shares beneficially owned, directly or indirectly, or over which control or direction is exercised by the directors and executive officers of APUC as a group is based upon information furnished by the directors and executive officers.

## 8.2 Audit Committee

Under the By-Laws, 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 (Chairman), 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 charter for Audit Committee 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 his responsibilities as a member of the Audit Committee.

Mr. Ball has extensive financial experience, with 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. Moore has extensive financial experience and is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank.

Mr. Moore has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the designation of Ch. Dir. (Chartered Director)

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.

### 8.2.3 Pre-Approval Policies and Procedures

All non-audit services proposed to be provided by APUC's auditors must be approved by the directors prior to the auditors providing such services.

| Services | 2016 Fees ($) | 2015 Fees ($) | 2014 Fees ($) |
|---|---|---|---|
| Audit Fees[1] | 2,765,607 | 2,420,650 | 1,965,600 |
| Audit-Related Fees[2] | 113,414 | 98,835 | 293,858 |
| Tax Compliance Fees[3] | — | — | — |
| Other Tax Fees[4] | 263,831 | 375,600 | 101,605 |
| All Other Fees | 5,800 | 19,500 | 28,000 |

[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 the Corporation's financial statements and not reported under Audit Fees, including audit procedures relate to regulatory commission filings and the audit of defined benefit pension plans.

[3] For preparation of income and other tax filings.

[4] For tax advisory and planning services.

## 8.3 Corporate Governance, Risk and Compensation Committees

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

In 2017, 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 directors have also put in place a Compensation Committee ("CC"), currently comprised of four directors of APUC, Ms. Samil (Chair), Mr. Ball, and Mr. Laney and Ms. Saidi.

## 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.

David Pasieka, the President of Liberty Utilities, was a director of Luxell Technologies Inc. when it filed a proposal under the Bankruptcy and Insolvency Act (Canada) on September 27, 2006. Luxell Technologies Inc. received a Certificate of Full Performance of Proposal under such legislation through a letter issued by its trustee in bankruptcy on January 14, 2008.

## 8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF (including Section 3.4, Business Associations with APMI and Senior Executives) and APUC's financial statements and MD&A for the fiscal year ended December 31, 2016, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but is also the President and CEO of Emera. Emera was a major shareholder of APUC until December 8, 2016 and had a strategic relationship with the Corporation until January 13, 2017. Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

# 9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

## 9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2016 are as follows:

### (i) Trafalgar Proceedings

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

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

In June, 2016, all of the above legal proceedings were settled pursuant to the terms outlined in the United States Bankruptcy Court for the Northern District of New York Order Approving Terms of Settlement which was entered into Bankruptcy Court on June 20, 2016. Pursuant to the global settlement, the Corporation and various Affiliates were allowed approximately U.S. $10.1 million which amount was received on June 30, 2016 (the "Litigation Proceeds"). The Litigation Proceeds were dispersed as more particularly outlined in the MD&A for the Nine Month Period Ending September 30, 2016 - Related Party Transactions.

### (ii) Long Sault Global Adjustment Claim

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

### (iii) Côte Ste-Catherine Water Lease Dues

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

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

## 9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2016, there have been:

(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; or

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

Except as disclosed elsewhere in this AIF, the only regulatory action involving APUC or its subsidiaries that is material in 2016 is as follows:

### (i) Park Water Condemnation

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

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

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

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

## 10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and MD&A as at and for the periods ended December 31, 2016, 2015 and 2014, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

## 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 CST Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax.

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, NY.

## 12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2016 (or prior to 2016 in the case of contracts that are still in effect) that are material to APUC:

(a) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures, as supplemented from time to time, including by the

Fourth Supplemental Trust Indenture dated January 17, 2017 providing for the issuance of $300,000,000 4.09% senior unsecured debentures due February 17, 2027.

(b) **U.S. Debt Private Placements:** Trust Indenture dated July 2, 2012 between LU GP1 and The Bank of New York Mellon providing for the creation and issuance of senior unsecured debentures, as supplemented from time to time.

(c) **Empire Acquisition:** Agreement and Plan of Merger, dated as of February 9, 2016, by and among Empire, Liberty Utilities (Central) Co., and Liberty SubCo. pursuant to which Liberty Utilities (Central) Co. agreed to acquire Empire and (indirectly) its subsidiaries by merger of Liberty Sub Corp. with and into Empire. APUC guaranteed the payment and performance of all obligations of Liberty Utilities (Central) Co. under the Agreement and Plan of Merger pursuant to a Guarantee dated as of February 9, 2016, by APUC in favour of Empire.

(d) **Underwriting Agreement:** Underwriting Agreement dated February 15, 2016, between LU Canada, as the selling debenture holder, and CIBC World Markets Inc. and Scotia Capital Inc. as co-lead underwriters, providing for the issuance and sale of not less than $1,000,000,000 and up to $1,150,000,000 principal amount of Debentures in connection with the Installment Debenture Offering.

(e) **Trust Indenture**: Trust Indenture dated as of March 1, 2016, between APUC and CST Trust Company, as trustee, providing for the creation and issuance of up to $1,150,000,000 principal amount of Debentures in connection with the Instalment Debenture Offering, as supplemented by a supplemental trust indenture dated January 31, 2017.

(f) **Instalment Receipts and Pledge Agreement:** Instalment Receipt and Pledge Agreement, dated March 1, 2016, between APUC, LU Canada, as the selling debenture holder, CIBC World Markets Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Desjardins Securities Inc., Raymond James Ltd., J.P. Morgan Securities Canada Inc., Wells Fargo Securities Canada, Ltd., Industrial Alliance Securities Inc., Canaccord Genuity Corp. and Cormark Securities Inc., as underwriters, and CST Trust Company, as custodian, and providing for the issuance of instalment receipts evidencing beneficial ownership of the Debentures in connection with the Installment Debenture Offering.

## 13. INTERESTS OF EXPERTS

Ernst & Young LLP is the external auditor of the Corporation and have confirmed that they are 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 they are independent accountants 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, 2016, which are available on SEDAR at www.sedar.com.

# SCHEDULE A

**Renewable - Hydroelectric, Solar and Wind Facilities**

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | Annual Average Expected Energy Production (GW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Hydroelectric - Ontario Facilities** | | | | | |
| **Facility:** Long Sault Rapids Hydro Facility<br><br>**Owner**: Algonquin Power (Long Sault) Partnership and N-R Power Partnership | 18 | Abitibi River near Cochrane, Ontario | **Electricity Purchaser:** OEFC | 111.6 | 2048 |
| **Facility:** Hurdman Dam Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 0.6 | Mattawa River near Mattawa, Ontario | **Electricity Purchaser:** IESO (formerly, the Ontario Power Authority) | 0[1] | 2031 |
| **Facility:** Campbellford Hydro Facility<br><br>**Owner**: Algonquin Power (Campbellford) Limited Partnership<br>**Owner**: Leased from Campbellford Public Utilities Commission, with lease expiring in 2018 | 4 | Trent River near Campbellford, Ontario | **Electricity Purchaser:** OEFC | 26.3 | 2019 |
| **Hydroelectric – Québec Facilities** | | | | | |
| **Facility:** Saint-Alban Hydro Facility<br><br>**Owner**: Nominee owner is SNC Lavalin Inc., beneficial owner is Algonquin Power Fund (Canada) Inc. | 8.2 | Ste-Anne River near the Village of Saint-Alban, Québec | **Electricity Purchaser:** Hydro-Québec | 37.7 | 2016 |
| **Facility:** Glenford Hydro Facility<br><br>**Owner**: Société en Commandite Chute Ford | 5 | Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec | **Electricity Purchaser:** Hydro-Québec | 24 | 2020 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | Annual Average Expected Energy Production (GW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Rawdon Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 2.5 | Ouareau River near the Village of Rawdon, Québec | **Electricity Purchaser:** Hydro-Québec | 15.2 | 2034 |
| **Facility:** Côte Ste-Catherine Hydro Facility<br><br>**Owner**: Algonquin Power (Mont-Laurier) Limited Partnership | 11.1 | St. Lawrence River near the Town of Ste.-Catherine, Québec | **Electricity Purchaser:** Hydro-Québec | Phase 1: 13.8 | Phase 1: 2020 |
| | | | | Phase II: 35.1 | Phase II: 2018 PPA has renewal option to 2043 |
| | | | | Phase III: 34.8 | Phase III: 2020 PPA has renewal option to 2045 |
| **Facility:** Ste-Raphaël Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 3.5 | Rivière de Sud near Québec City, Québec | **Electricity Purchaser**: Hydro-Québec | 21.7 | 2034 |
| **Facility:** Mont Laurier Hydro Facility<br><br>**Owner**: Algonquin Power (Mont-Laurier) Limited Partnership | 2.7 | Rivière-du-Lièvre in the Town of Mont Laurier, Québec | **Electricity Purchaser:** Hydro-Québec | 20.1 | 2027 |
| **Facility :** Rivière-du-Loup Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 2.6 | Rivière-du-Loup near the Town of Rivière-du-Loup, Québec | **Electricity Purchaser:** Hydro-Québec | 17.3 | 2035 |
| **Facility:** Hydraska Hydro Facility<br><br>**Owner**: Algonquin Power Trust | 2.3 | Yamaska River near the Town of St.-Hyacinthe, Québec | **Electricity Purchaser:** Hydro-Québec | 9.1 | 2034 |
| **Facility:** Ste-Brigitte Hydro Facility<br><br>Owner: Algonquin Power Fund (Canada) Inc. | 4.2 | Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates:** $0.0832/kW-hr (Jan-Feb) | 12.6 | 2034 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | Annual Average Expected Energy Production (GW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Belleterre Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 2.2 | Winneway River in the Municipality of Laforce, Québec | **Electricity Purchaser:** Hydro-Québec | 11.2 | 2033 |
| **Facility:** Donnacona Hydro Facility<br><br>**Owner**: Société Hydro-Donnacona, S.E.N.C. | 4.8 | Jacques Cartier River near Donnacona, Québec | **Electricity Purchaser:** Hydro-Québec | 21.5 | 2022<br><br>PPA has renewal option to 2047 |
| **Facility:** Arthurville Hydro Facility<br><br>**Owner**: Algonquin Power Trust | 0.7 | Rivière du Sud downstream from Ste-Raphaël | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: No target rate as the site is expected to be offline | 0[2] | 2033 |
| **Hydroelectric - Western Canada Facility** | | | | | |
| **Facility:** Dickson Dam Hydro Facility<br><br>**Owner:** Algonquin Power Operating Trust | 15 | Innisfail, Alberta | **Electricity Purchaser:** AESO & Capital Power | 65 | 2016 |
| **Hydroelectric - Maritime Facilities** | | | | | |
| **Facility:** Tinker Hydro Facility<br><br>**Owner**: Algonquin Tinker Gen Co. | 34 | Perth-Andover, New Brunswick | **Electricity Purchaser:** AES<br>Town of Perth-Andover | 142 | Perth-Andover Contract through 2021 |
| **Facility:** Caribou Hydro Facility<br><br>**Owner:** Algonquin Northern Maine Gen Co. | 0.9 | Caribou, Maine | **Electricity Purchaser:** AES | 1.3 | n/a |
| **Facility:** Squa Pan Hydro Facility<br><br>**Owner**: Algonquin Northern Maine Gen Co. | 1.4 | Squa Pan Lake, near Caribou Maine | **Electricity Purchaser:** AES | 0.7 | n/a |
| **Solar Facilities** | | | | | |
| **Facility:** Cornwall Solar Facility<br><br>**Owner**: Cornwall Solar Inc. | 10 | Cornwall, Ontario | **Electricity Purchaser:** IESO (formerly, the Ontario Power Authority) | 14.8 | 2034 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | Annual Average Expected Energy Production (GW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Bakersfield Solar Facility<br><br>**Owner**: Algonquin SKIC20 Solar, LLC | 20 | Kern County, California | **Electricity Purchaser:** PG&E<br><br>**Rates:** $0.883/kWh | 53.1 | 2035 |
| **Facility:** Bakersfield II Solar Facility<br><br>**Owner**: Algonquin SKIC10 Solar, LLC | 10 | Kern County, California | **Electricity Purchaser:** (Southern California Edison Company) | 26 | 2037 (20 years after COD) |
| **Facility:** Great Bay Solar Facility<br><br>**Owner**: Great Bay Solar Holdings, LLC | 75 | Somerset County, Maryland | **Electricity Purchaser:** (Under Development - U.S. General Services Administration) | 152 | 2027 (10 years after COD) |
| **Wind - Canadian Facilities** | | | | | |
| **Facility:** Morse Wind Facility<br><br>**Owner**: Algonquin Power Morse LP | 23 | Morse, Saskatchewan | **Electricity Purchaser:** SaskPower | 108.8 | 2035 (20 years after COD) |
| **Facility:** Red Lily Wind Facility<br><br>**Owner**: Red Lily Wind Energy Partnership | 26.4 | Saskatchewan | **Electricity Purchaser:** SaskPower | 88.4 | 2036 |
| **Facility**: St.-Damase Wind Facility<br><br>**Owner**: Société en Commandité Fleur de Lis Éoliennes Saint-Damase | 24 | Saint-Damase, Québec | **Electricity Purchaser**: Hydro-Quebec | 76 | 2034 |
| **Facility**: St. Leon Wind Facility<br><br>**Owner**: St. Leon Wind Energy LP | 104 | St. Leon, Manitoba | **Electricity Purchaser**: Manitoba Hydro | 372 | 2026 + one 5 year extension |
| **Facility:** St. Leon II Wind Facility<br><br>**Owner**: St. Leon II Wind Energy LP | 16.5 | St. Leon, Manitoba | **Electricity Purchaser:** Manitoba Hydro | 58.1 | 2037 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | Annual Average Expected Energy Production (GW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Val-Éo Wind Facility<br><br>**Owner**: Éoliennes Belle-Rivière, société en commandite | 24 | Saint-Gédéon, Québec | **Electricity Purchaser:** (Under Development – Hydro-Quebec) | 66 | 2037 (20 years after COD) |
| **Facility:** Amherst Island Wind Facility<br><br>**Owner**: Windlectric Inc. | 75 | Stella, Ontario | **Electricity Purchaser:** (Under Development - IESO [formerly, the Ontario Power Authority]) | 247 | 2038 (20 years after COD) |
| **Facility**: Chaplin Wind Facility<br><br>**Owner**: Windlectric Inc. | 177 | Chaplin, Saskatchewan | **Electricity Purchaser**: (Under Development - SaskPower) | 720 | 2044/5 (25 years after COD) |
| **Wind - U.S. Facilities** | | | | | |
| **Facility:** Minonk Wind Facility<br><br>**Owner**: Minonk Wind, LLC | 200 | Minonk, Illinois | **Electricity Purchaser:** PJM North Illinois | 674 | 2022 [2] |
| **Facility:** Senate Wind Facility<br><br>**Owner:** Senate Wind, LLC | 150 | Graham, Texas | **Electricity Purchaser:** ERCOT North markets | 520 | 2027 [2] |
| **Facility:** Sandy Ridge Wind Facility<br><br>**Owner:** Sandy Ridge Wind, LLC | 50 | Tyrone, Pennsylvania | **Electricity Purchaser:** PJM West | 158.3 | 2022 [2] |
| **Facility:** Shady Oaks Wind Facility<br><br>**Owner:** GSG6, LLC | 109.5 | Lee County, Illinois | **Electricity Purchaser:** Commonwealth Edison | 352.4 | 2032 |
| **Facility:** Odell Wind Facility<br><br>**Owner**: O'Dell Wind Farm, LLC. | 200 | Cottonwood, Jackson, Martin and Watonwan Counties Minnesota | **Electricity Purchaser:** (Under Development - Northern States Power) | 822 | 2036 (20 years after COD) |
| **Facility:** Deerfield Wind Facility<br><br>**Owner**: Algonquin Power (Deerfield Holdings) Inc. | 150 | Central Michigan | **Electricity Purchaser:** (Under Development – Wolverine Power Supply Co-operative) | 555.2 | 2037 (20 years after COD) |

[1] Scheduled to be offline in 2017. No decision has been made as to the timing of repairing these facilities.

[2] APUC currently has hedge agreements in place in respect of each facility. See “Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation – Renewable – Wind Power - Material Facilities”.

# SCHEDULE B

## Thermal - Biomass, Cogeneration, and Diesel Facilities

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser | Annual Average Expected Energy Production (GW-hrs) | Year of Expiry of PPA | Lease Expiry Year |
|---|---|---|---|---|---|---|
| **Thermal - Cogeneration Facilities** | | | | | | |
| **Facility:** Sanger Facility<br><br>**Owner**: Algonquin Power Sanger LLC | 56 | Sanger, California | **Electricity Purchaser:** PG&E | 140.9 | 2021 | Owned |
| **Facility:** Windsor Locks Facility<br><br>**Owner**: Algonquin Power Windsor Locks LLC | 71 | Windsor Locks, Connecticut | **Electricity Purchaser:** ISO New England Ahlstrom | 116.5 | Merchant 2027 | 2027 |
| **Facility:** Kirkland Lake<br><br>**Ownership:** 32.4% of the Class B non-voting shares | 132 | Kirkland Land, Ontario | **Electricity Purchaser:** OEFC (Baseload) & IESO (Gas Peaker) | 657.8 | 2030(Baseload) & 2035 (Gas Peaking) | 2035 |
| **Thermal - Diesel Facilities** | | | | | | |
| **Facility:** Tinker Thermal Facility<br><br>**Owner**: Algonquin Tinker Gen Co. | 1 | Perth-Andover, New Brunswick | **Electricity Purchaser:** Not Under Contract<br>**Rates**: Capacity only | 0[1] | NA | Owned |

[1] Available to provide capacity only. The thermal facilities located in Northern Maine and New Brunswick are not considered strategic to APUC. As a result APUC is taking steps to shutdown these facilities.

# SCHEDULE C

**Wastewater and Water Distribution Facilities**

| Utility | Owner | Location | Type of Utility | December 31, 2016 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| Black Mountain Sewer System | Liberty utilities (Black Mountain Sewer) Corp. | Carefree, Arizona | Wastewater | 2,463 | Pursuant to ACC decision 75510 |
| Gold Canyon Sewer System | Liberty Utilities (Gold Canyon Sewer) Corp. | Gold Canyon Arizona | Wastewater | 6,970 | Pursuant to ACC decision 69664 |
| Bella Vista Water System | Liberty Utilities (Bella Vista Water) Corp. | Sierra Vista, Arizona | Water Distribution | 9,743 | Pursuant to ACC decision 75809 |
| Tall Timbers Waste System | Liberty Utilities (Tall Timbers Sewer) Corp. | Tyler, Texas | Wastewater | 2,340 | Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350 |
| Woodmark Waste System | Liberty Utilities (Woodmark Sewer) Corp. | Tyler, Texas | Wastewater | 1,947 | Pursuant to TCEQ docket 2014-0064-UCR, SOAH docket 582-14-2348, PUCT docket 42831 |
| LPSCo Water & Waste System | Liberty Utilities (Litchfield Park Water & Sewer) Corp. | Litchfield, Park, Arizona | Wastewater<br>Water Distribution | 22,250<br>19,098 | Pursuant to ACC docket 74437 |
| Fox River Water & Waste System | Liberty Utilities (Fox River Water) LLC | Sheridan, Illinois | Wastewater<br>Water Distribution | 245<br>241 | Per customer agreement[3]<br>US $240.08<br>US $141.61 |
| Timber Creek Water & Waste System | Liberty Utilities (Missouri Water) LLC | DeSoto, Missouri | Wastewater<br>Water Distribution | 17<br>26 | Pursuant to MOPSC decision WR-2006-4025 |
| Holiday Hills Water System | Liberty Utilities (Missouri Water) LLC | Branson, Missouri | Water Distribution | 502 | Per MOPSC Case WR-2006-4025 |
| Ozark Water & Waste System | Liberty Utilities (Missouri Water) LLC | Kimberling City, Missouri | Wastewater<br>Water Distribution | 240<br>262 | Pursuant to MOPSC decision WR-2006-4025 |
| Holly Lake Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | Hawkins, Texas | Wastewater<br>Water Distribution | 137<br>2,011 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |
| Big Eddy Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | Flint, Texas | Wastewater<br>Water Distribution | 424<br>551 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |
| Piney Shores Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | Conroe, Texas | Wastewater<br>Water Distribution | 281<br>280 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |

| Utility | Owner | Location | Type of Utility | December 31, 2016 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| Hill Country Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | New Braunfels, Texas | Wastewater<br>Water Distribution | 425<br>230 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |
| Rio Rico Water & Waste System | Liberty Utilities (Rio Rico Water & Sewer) Corp. | Rio Rico, Arizona | Wastewater<br>Water Distribution | 2,326<br>7,041 | Pursuant to ACC decision 75809 |
| Northern Sunrise Water System | Liberty Utilities (Northern Sunrise Water) Corp. | Sierra Vista, Arizona | Water Distribution | 370 | Pursuant to ACC decision 75809 |
| Southern Sunrise Water System | Liberty Utilities (Southern Sunrise Water) Corp. | Sierra Vista, Arizona | Water Distribution | 896 | Pursuant to ACC decision 75809 |
| Entrada Del Oro Waste System | Liberty Utilities (Entrada Del Oro Sewer) Corp. | Gold Canyon, Arizona | Wastewater | 350 | Pursuant to ACC decision 68306 |
| Seaside Resort Water & Waste System | Liberty Utilities (Seaside Water) LLC | Galveston, Texas | Water Distribution<br>Wastewater | 159<br>163 | Per customer agreement[2]<br>US $166.68<br>US $165.45 |
| Noel Water System | Liberty Utilities (Missouri Water) LLC | Noel, Missouri | Water Distribution | 687 | Pursuant to MOPSC decision WR-2009-0395 |
| KMB Water & Waste System | Liberty Utilities (Missouri Water) LLC | Jefferson, Franklin and Cape Girardeau counties in Missouri | Wastewater<br>Water Distribution | 179<br>555 | Pursuant to MOPSC decision WO-2010-0345 |
| Pine Bluff Water System | Liberty Utilities (Pine Bluff Water) Inc. | Pine Bluff, Arkansas | Water Distribution | 18,833 | Pursuant to APSC docket No. 14-020-U |
| White Hall Water System | Liberty Utilities (White Hall Water) Corp., and Liberty Utilities (White Hall Sewer) Corp. | White Hall, Arkansas | Wastewater<br>Water Distribution | 1,852<br>1,949 | Pursuant to City Ordinance Nos. 477 and 478 |
| Liberty Utilities (Park Water) Corp. | Western Water Holdings, LLC | Downey, California | Water Distribution | 27,413 | Pursuant to CPUC decision 16-01-009 |
| Liberty Utilities (Apple Valley Ranchos Water) Corp. | Liberty Utilities (Park Water) Corp. | Apple Valley, California | Water Distribution | 20,349 | Pursuant to CPUC decision 15-11-030 |
| Mountain Water Company | Liberty Utilities (Park Water) Corp. | Missoula, Montana | Water Distribution | 22,933 | Pursuant to MPSC docket D2012.7.81, Order No. 7251c |
| Woodson-Hensley Water Company | Liberty Utilities (Woodson-Hensley Water) Corp. | Hensley, Arkansas | Water Distribution | 456 | |
| **Total connections** | | | | **177,194** | |

| Utility | Owner | Location | Type of Utility | Connections Acquired January 1, 2017 | Rates[2] |
|---|---|---|---|---|---|
| Empire | The Empire District Electric Company | Joplin, Missouri | Distribution | 5,000 | MO - ER-2016-0023<br>AR - 13-111-U<br>KS - 11-EPDE-856-RTS<br>OK - PUD 201100082 |

[1] Inclusive of vacant connections. Excludes connections associated with operating and maintenance contracts.

[2] See www.libertyutilities.com for complete rate tariffs.

[3] Rates charged per agreement with developer.

# SCHEDULE D

## Electrical Distribution Facilities

| Utility | Owner | Location | Type of Utility | December 31, 2016 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| CalPeco Electric System | Liberty Utilities (CalPeco Electric) LLC | Lake Tahoe, California | Electricity Distribution | Residential – 42,946<br><br>Commercial & Industrial – 5,851 | Rates pursuant to CPUC decision 12-16-024 |
| Granite State Electric System | Liberty Utilities (Granite State Electric) Corp | Salem, New Hampshire | Electricity Distribution | Residential – 38,267<br><br>Commercial & Industrial – 6,648 | Rates pursuant to NHPUC docket DE 13-063, Order 25,638 |
| **Total Connections** | | | | **93,712** | |

| Utility | Owner | Location | Type of Utility | Connections Acquired January 1, 2017 | Rates[2] |
|---|---|---|---|---|---|
| Empire | The Empire District Electric Company | Joplin, Missouri | Electricity Generation, Transmission & Distribution | 170,000 | MO - ER-2016-0023<br>AR - 13-111-U<br>KS - 11-EPDE-856-RTS<br>OK - PUD 201100082 |

[1] Inclusive of vacant connections.

[2] See www.libertyutilities.com for complete rate tariffs.

# SCHEDULE E

## Natural Gas Distribution Facilities

| Utility | Owner | Location | Type of Utility | December 31, 2016 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| EnergyNorth Gas System | Liberty Utilities (EnergyNorth Natural Gas) Corp. | Londonderry, New Hampshire | Natural Gas Distribution | Residential – 81,059<br>Commercial & Industrial – 9,112 | Rates pursuant to NHPUC docket DG 14-180, Order 25,797 |
| Peach State Gas System | Liberty Utilities (Peach State Natural Gas) Corp. | Columbus, Gainesville, GA | Natural Gas Distribution | Residential – 60,233<br>Commercial & Residential – 4,287 | Rates pursuant to GPSC docket #34734 Document #166,984 |
| New England Gas System | Liberty Utilities (New England Natural Gas Company) Corp. | Fall River, North Attleboro, Plainville, Westport, Swansea, Somerset, Massachusetts | Natural Gas Distribution | Residential – 50,996<br>Commercial & Industrial – 3,727 | Rates pursuant to M.D.P.U 15-75 |
| Midstates Gas System - Illinois | Liberty Utilities (Midstates Natural Gas) Corp. | Salem, Virden, Vandalia, Xenia, Metropolis, Illinois | Natural Gas Distribution | Residential – 20,474<br>Commercial & Industrial – 2,160 | Rates pursuant to ICC decision IL-14-0371 |
| Midstates Gas System - Iowa | Liberty Utilities (Midstates Natural Gas) Corp. | Keokuk, Iowa | Natural Gas Distribution | Residential – 3,896<br>Commercial & Industrial – 499 | Rates pursuant to IUB decision TF-01-68 |
| Midstates Gas System - Missouri | Liberty Utilities (Midstates Natural Gas) Corp. | Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri | Natural Gas Distribution | Residential – 48,915<br>Commercial & Industrial – 6,991 | Rates pursuant to MOPSC decision GR-2014-0152 |
| New Hampshire Gas System | Liberty Utilities (EnergyNorth Natural Gas) Corp. | Keene, New Hampshire | Propane Gas Distribution | Residential – 744<br>Commercial & Industrial – 398 | |
| **Total Connections** | | | | **293,491** | |

| Utility | Owner | Location | Type of Utility | Connections Acquired January 1, 2017[1] | Rates[2] |
|---|---|---|---|---|---|
| Empire District Gas System | The Empire District Gas Company | Joplin, Missouri | Natural Gas Distribution | 43,000 | MO - ER-2016-0023<br>AR - 13-111-U<br>KS - 11-EPDE-856-RTS<br>OK - PUD 201100082 |

[1] Inclusive of vacant connections. Excludes Transportation connections.

[2] 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;

(c) be an unrelated director for the purposes of the Toronto Stock Exchange (the " **TSX**") Corporate Governance Policy; and

(d) 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 the TSX Corporate Governance Policy, NI 52 110 and other applicable laws and regulations.

2 . 4 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. A majority of the members of the Committee shall constitute a quorum and 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 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 independent 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, 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 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, whether at any time the incumbent external auditor should be removed from office, and 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 devisable 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 ensure 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) Related Party Transactions – The Committee shall review and approve any transaction between the Corporation and a related party and any transaction involving the Corporation and another party in which the parties' relationship could enable the negotiation of terms on other than an independent, arms' length basis.

(h) 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.

(i) Liaison – The Committee shall review and ensure that 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.

(j) 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.

(k) 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 – On at least an annual basis, the Committee shall 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 on an annual basis and at such other times, as it considers appropriate.

**9 LEGISLATIVE AND REGULATORY CHANGES**

9.1 Compliance – It is the Board' 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 annually 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.

# SCHEDULE G

## GLOSSARY OF TERMS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated.

"**ACC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group"*.

*"***Acquisition Facility***"* has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2017 - Corporate"*.

*"***Empire Acquisition Credit Facilities** " has the meaning ascribed thereto under *"Caution Concerning Forward-Looking Statements and Forward-Looking Information"*.

"**ADEQ**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Principal Markets and Regulatory Environments"*.

"**Adjusted EBITDA**" means adjusted earnings before interest, taxes, depreciation and amortization.

"**AESO**" has the meaning ascribed thereto under *"Description of the Business - Description of Operations - Business Development"*.

"**Alberta Power Pool**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods"*.

"**Ahlstrom**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities"*.

"**AIF**" or "**Annual Information Form**" means this annual information form.

"**APCH**" means Algonquin Power (Canada) Holdings Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APCI**" means Algonquin Power Corporation Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APCo**" means Algonquin Power Co. See *"Corporate Structure - Name, Address and Incorporation"*.

"**APFA**" means Algonquin Power Fund (America) Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APOT**" means Algonquin Power Operating Trust. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Apple Valley**" means Liberty Utilities (Apple Valley Ranchos Water) Corp.

"**Apple Valley Ranchos Water System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APSC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group"*.

"**APT**" means Algonquin Power Trust. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APUC**" (or the "Corporation") means Algonquin Power & Utilities Corp including, for reporting purposes only, the direct or indirect subsidiary

entities of APUC and partnership interests held by APUC and its subsidiaries. See *“Corporate Structure - Name, Address and Incorporation”*.

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator.

"**Bakersfield I Solar Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Bakersfield II Solar Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Black Mountain System**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**Board**" means the APUC Board of Directors.

"**BRRBA**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments".*

"**CalPeco**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**CalPeco Electric System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

"**COG**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Natural Gas Distribution Systems - Material Facilities".*

"**Common Shares**" means the common shares of APUC created pursuant to a certificate and articles of arrangement dated October 27, 2009. See *"Corporate Structure - Name, Address and Incorporation"*.

"**Co-Owners**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**Cornwall Solar**" means Cornwall Solar Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Cornwall Solar Facility***"* has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Corporate Credit Facility**" has the meaning ascribed thereto under *"Risk Factors - Treasury Risk - Interest Rate"*

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

"**Côte Ste.-Catherine Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**CPCN**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Regulatory Regimes - Utility Distribution Systems."*

"**CPUC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

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

"**Debentures**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2017 - Corporate".*

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

"**Deerfield Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**Dickson Dam Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**Donnacona Hydro Facility**" has the meaning ascribed thereto under "*Corporate Structure -Intercorporate Relationships - Subsidiaries*".

"**Donnaconna LP**" has the meaning ascribed thereto under "*Corporate Structure - Intercorporate Relationships - Subsidiaries*".

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization.

"**ECAC**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments".*

"**Emera**" means Emera Inc. See *"Description of Capital Structure - Private Placements of Subscription Receipts and Common Shares to Emera".*

"**Empire**" means Empire District Electric Company.

"Empire **Acquisition**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**EnergyNorth Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**ERCOT**" has the meaning ascribed thereto under "*Description of the Business - Renewable Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods*".

"**ESA**" has the meaning ascribed thereto under "*Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities*".

"**EWGs**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States".*

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

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

"**FPA**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States".*

"**FBO**" means funded by others.

"**Final Instalment**" has the meaning ascribed thereto under "*Description of Capital Structure - Convertible Debentures*"

"**Final Instalment Date**" has the meaning ascribed thereto under *"Description of Capital Structure - Convertible Debentures"*

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

“**Gamesa**” has the meaning ascribed thereto under *“General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.*“**Gold Canyon Water System**” has the meaning ascribed thereto under *“Description of the Business - Liability Utilities Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities”.*

"**GPSC**" means Georgia Public Service Commission.

"**GRAM**" means the Georgia Rate Adjustment Mechanism.

"**Great Bay Solar Project**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Granite State Electric System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**GW**" means a gigawatt.

"**Hydro-Québec**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group".*

"**IESO**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group".*

"**ISO**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - Canada".*

"**ISO-NE**" has the meaning ascribed thereto under the heading *"Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Principal Markets and Distribution Methods".*

"**ISRS**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group".*

"**kV**" means kilovolt.

"**Liberty SubCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Liberty Utilities**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Long Sault**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Long Sault Global Adjustment Claim".*

"**Long Sault Hydro Facility**" has the meaning ascribed thereto under "*Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group*".

"**LLC**" means Limited Liability Company.

"**LPSCo System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group".*

"**LS Partnership**" means Algonquin Power (Long Sault) Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

"**LU GP1**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**LU GP2**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

"**MBR Authority**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Regulatory Regimes- Power Generation - United States"*.

"**MD&A**" means the Corporation's management's discussion and analysis.

"**Midstates Gas Systems**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Liberty Utilities Group".*

"**Minonk Wind Facility**" means the Minonk wind energy facility. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**MMBTU**" means one million British Thermal Units.

**"Mont-Laurier Hydro Facility"** means Mont-Laurier hydroelectric generating facility. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**Mont-Laurier Partnership**" means Algonquin Power (Mont-Laurier) Limited Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

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

"**Morse Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**MNPSC**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

"**Mountain Water**" means Mountain Water Company.

**"MPSC"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group".*

**"MW"** means megawatt.

**"MVA"** means mega-volt ampere.

"**New England Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Liberty Utilities Group".*

"**New Facility**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2015 - Corporate*".

"**NHPUC**" means the New Hampshire Public Utilities Commission. See *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group".*

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

"**Northern Maine Gen Co.**" means Algonquin Northern Maine Gen Co., a Wisconsin company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group*".

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

"**O&M**" means an operation and maintenance service agreement.

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

**"Odell Wind Facility"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group"*.

"**Odell SponsorCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group*".

"**OEB**" means the Ontario Energy Board.

"**OEFC**" means Ontario Electric Financial Corporation.

"**OPA**" means the Ontario Power Authority.

"**Optionee**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Options**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Park Water**" means the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp.

"**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".*

**"Peach State"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Peach State Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**PG&E**" means Pacific Gas & Electric Company. See *"Description of the Business - Renewable Generation Group-- Description of Operations -- Solar Power Generating Facilities - Material Facilities".*

"**PGA**" means Purchased Gas Adjustment.

"**Pine Bluff Water System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*

"**PJM**" means PJM Interconnection. See *"Description of the Business - Renewable Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

"**PPA**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group".*

"**PSU**" has the meaning ascribed thereto under "*Description of Capital Structure - Performance Share Units*".

"**PTC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Renewable Generation Group Highlights".*

"**PUHCA**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States".*

"**QFs**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States".*

"**Rating Agencies**" means collectively DBRS, and S&P, and "Rating Agency" means one of the Rating Agencies.

"**REC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group".*

"**Red Lily Wind Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Renewable Generation Group Highlights".*

"**Red Lily Partnership**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Red Lily II LP***"* has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

---

"**Renewable Generation Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Rio Rico System**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

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

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

"**Saint-Damase Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

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

"**Sanger LLC**" means Algonquin Power Sanger LLC, a California limited liability company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**Sanger Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**SaskPower**" means Saskatchewan Power Corporation.

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

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

"**Series C Shares**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

**"Series D Shares"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate".*

"**Shady Oaks Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

**"Squa Pan Hydro Facility"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**St. Alban Hydro Facility**" means the St. Alban hydroelectric generating facility.

"**Ste. Brigitte Hydro Facility**" means the St. Brigitte hydroelectric generating facility.

"**St. Leon II Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

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

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**St. Leon Trust**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

"**St. Leon Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group"*.

"**Tinker Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*

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

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

"**U.S. Wind Portfolio**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group".*

"**Val-Éo Wind Project**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Windlectric**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Windsor LLC**" means Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

**"Windsor Locks Thermal Facility"** has the meaning ascribed thereto under the heading *"Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**White Hall Water System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group".*

"**White Hall Waste System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group".*

"**White Hall Water and Waste System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

**"WP SponsorCo"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group".*

**Consolidated Financial Statements of**
**Algonquin Power & Utilities Corp.**
**For the years ended December 31, 2016 and 2015**

# MANAGEMENT'S REPORT

## Financial Reporting

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

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

## Internal Control over Financial Reporting

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

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

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

March 10, 2017

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

**INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM**

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

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

**Management's Responsibility for the Consolidated Financial Statements**

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

**Auditors' Responsibility**

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

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

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

**Opinion**

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

**Other Matter**

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

/s/ Ernst & Young LLP
Chartered Professional Accountants,
Licensed Public Accountants
Toronto, Canada
March 10, 2017

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

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

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

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

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

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

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

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

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

/s/ Ernst & Young LLP
Chartered Professional Accountants,
Licensed Public Accountants
Toronto, Canada
March 10, 2017

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

*(thousands of Canadian dollars)*

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

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

*(thousands of Canadian dollars)*

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

See accompanying notes to consolidated financial statements

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

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

See accompanying notes to consolidated financial statements

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

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

See accompanying notes to consolidated financial statements

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

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

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

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

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

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

See accompanying notes to consolidated financial statements

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

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

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

See accompanying notes to consolidated financial statements

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

## 1. Significant accounting policies

(a) Basis of preparation

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

(b) Basis of consolidation

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

(c) Business combinations, intangible assets and goodwill

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

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

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

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

(d) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB")ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

## 1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

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

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

(e) Cash and cash equivalents

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

(f) Restricted cash

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

(g) Accounts receivable

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

(h) Natural gas in storage

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

(i) Supplies and consumables inventory

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

(j) Property, plant and equipment

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

**1. Significant accounting policies (continued)**

(j) Property, plant and equipment (continued)

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

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

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

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

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

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

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

## 1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

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

(k) Impairment of long-lived assets

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

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

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

(l) Variable interest entities

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

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

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

(m) Long-term investments and notes receivable

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

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

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

## 1. Significant accounting policies (continued)

(n) Pension and other post-employment plans

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

(o) Asset retirement obligations

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

(p) Share-based compensation

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

(q) Non-controlling interests

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

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

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

## 1. Significant accounting policies (continued)

(q) Non-controlling interests (continued)

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

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

(r) Recognition of revenue

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

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

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

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

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

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

Revenue is recorded net of sales taxes.

## 1. Significant accounting policies (continued)

(s) Foreign currency translation

APUC's reporting currency is the Canadian dollar.

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

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

(t) Income taxes

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

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

(u) Financial instruments and derivatives

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

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

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

## 1. Significant accounting policies (continued)

(u) Financial instruments and derivatives (continued)

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

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

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

(v) Fair value measurements

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

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

(w) Commitments and contingencies

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

(x) Use of estimates

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

## 2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB Issued ASU 2017-03 Accounting Changes and Error Corrections (Topic 250) and Investments—Equity Method and Joint Ventures (Topic 323) to enhance disclosures of new accounting standards, including a comparison to current accounting policies, and the progress status of implementation. This

ASU applies to ASU No. 2014-09, Revenue from Contracts with Customers (Topic

606); ASU No. 2016-02, Leases (Topic 842); and ASU 2016-03, Financial Instruments - Credit

Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, and subsequent

amendments. The Company has enhanced its disclosures regarding the impact that recently issued accounting standards will have on the Company's consolidated financial statements when such standards are adopted in a future period.

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

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

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

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

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

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

The FASB issued ASU 2014-15, Presentation of Financial Statements - Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity’s management should evaluate whether there are conditions or events that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the financial statements are issued. The adoption of this standard as of December 31, 2016 had no impact on the Company’s consolidated financial statements. Its implementation leveraged existing financial reporting processes.

## 2. Recently issued accounting pronouncements (continued)

(a) Recently adopted accounting pronouncements (continued)

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

(b) Recently issued accounting guidance not yet adopted

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

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

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

The FASB issued ASU 2016-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This ASU amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

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

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

## 2. Recently issued accounting pronouncements (continued)

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

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

The FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718) to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The adoption of this standard is expected to have no material impact on the Company's consolidated financial statements. The Company intends to continue with its current accounting policy to record the stock-based compensation expense adjusted for estimated forfeitures.

The FASB issued ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments to clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this Update is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The standard is effective for fiscal years and interim periods beginning after December 15, 2016. Early adoption is permitted. The adoption of this standard is not expected to have an impact on the Company’s financial position or results of operations.

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

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

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

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

## 2. Recently issued accounting pronouncements (continued)

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

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

## 3. Business acquisitions and development projects

(a) Acquisition of Empire

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

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

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

(b) Luning Solar Facility

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

(c) Bakersfield II Solar Facility

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

## 3. Business acquisitions and development projects (continued)

(c) Bakersfield II Solar Facility (continued)

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

(d) Wind Turbine Components Purchase

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

(e) Acquisition of Park Water System

On January 8, 2016, the Company completed the acquisition of Western Water Holdings, LLC which is the parent company of Park Water Company ("Park Water System"), a regulated water distribution utility. Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and western Montana. Those three utilities were named Park Water Company, Apple Valley Ranchos Water Co. and Mountain Water Company. The total purchase price for the Park Water System is $353,077 (U.S.$249,540), net of the debt assumed of U.S.$91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed in the consolidated statements of operations.

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

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

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

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

## 3. Business acquisitions and development projects (continued)

(e) Acquisition of Park Water System (continued)

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

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

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

The Park Water System contributed revenue of $96,695 and pre-tax net earnings of $25,374 to the Company's consolidated financial results for the year ended December 31, 2016.

(f) Commercial operation of Morse Wind Facility

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

(g) Acquisition of New Hampshire Gas

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

(h) Commercial operation of Bakersfield Solar I Facility

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

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

## 3. Business acquisitions and development projects (continued)

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

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

(i) Acquisition of Shady Oaks Wind Facility

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

## 4. Accounts receivable

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

## 5. Property, plant and equipment

Property, plant and equipment consist of the following:

| 2016 | Cost | Accumulated depreciation | Net book value |
|---|---|---|---|
| Generation | $ 2,613,267 | $ 419,227 | $ 2,194,040 |
| Distribution | 2,638,488 | 462,454 | 2,176,034 |
| Land | 60,868 | — | 60,868 |
| Equipment and other | 139,961 | 44,700 | 95,261 |
| Construction in progress | | | |
| Generation | 197,405 | — | 197,405 |
| Distribution | 166,338 | — | 166,338 |
| | $ 5,816,327 | $ 926,381 | $ 4,889,946 |

| 2015 | Cost | Accumulated depreciation | Net book value |
|---|---|---|---|
| Generation | $ 2,138,748 | $ 358,200 | $ 1,780,548 |
| Distribution | 2,075,059 | 265,741 | 1,809,318 |
| Land | 23,258 | — | 23,258 |
| Equipment and other | 129,555 | 37,443 | 92,112 |
| Construction in progress | | | |
| Generation | 68,265 | — | 68,265 |
| Distribution | 103,669 | — | 103,669 |
| | $ 4,538,554 | $ 661,384 | $ 3,877,170 |

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

## 5. Property, plant and equipment (continued)

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

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

## 6. Intangible assets and goodwill

Intangible assets consist of the following:

| 2016 | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Power sales contracts | $ 72,207 | $ 44,641 | $ 27,566 |
| Customer relationships | 35,979 | 10,999 | 24,980 |
| Interconnection agreements | 13,000 | 557 | 12,443 |
| | $ 121,186 | $ 56,197 | $ 64,989 |

| 2015 | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Power sales contracts | $ 75,239 | $ 40,244 | $ 34,995 |
| Customer relationships | 37,083 | 10,371 | 26,712 |
| Interconnection agreements | 13,000 | — 230 | 12,770 |
| | $ 125,322 | $ 50,845 | $ 74,477 |

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

Changes in goodwill are as follows:

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

## 7. Regulatory matters

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

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

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

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

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

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

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

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

On February 10, 2016, the New England Gas System received a Final Order from the Massachusetts Department of Public Utilities approving an annual revenue increase of U.S.$7,800 effective March 1, 2016 and an additional U.S. $500 effective March 1, 2017.

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

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

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

## 7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

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

(a) Environmental remediation

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

(b) Pension and post-employment benefits

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

(c) Commodity costs adjustment

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

## 7. Regulatory matters (continued)

(c) Commodity costs adjustment (continued)

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

(d) Rate case costs

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

(e) Rate adjustment mechanism

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

(f) Debt premium

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

(g) Taxes

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

(h) Cost of removal

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

(i) Rate-base offset

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

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

## 8. Long-term investments

Long-term investments consist of the following:

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

(a) Red Lily I Wind Facility

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

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

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

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

## 8. Long-term investments (continued)

(b) Deerfield Wind Project

On October 19, 2015, the Company acquired a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 150 MW construction-stage wind development project ("Deerfield Wind Project") in the state of Michigan.

Upon the acquisition of the Deerfield Wind Project by Deerfield SponsorCo, the two members each contributed U.S.$1,000 to the capital of Deerfield SponsorCo. On October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S.$262,900 and a tax equity agreement was executed. Concurrently, each member contributed another U.S.$19,891 to the capital of Deerfield SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments at any time prior to the date that is 90 days following commencement of operations expected early 2017. The interest capitalized during the year ended December 31, 2016 to the investment while the Deerfield Wind Project is under construction amounts to $6,072 (2015 - $94).

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

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

(c) Odell Wind Facility

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

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

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

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

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

## 8. Long-term investments (continued)

(d) Amherst Island Wind Project

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

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

(e) Natural gas pipeline developments

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

(f) Development loans

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

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

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

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

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

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

## 9. Long-term debt

Long-term debt consists of the following:

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

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

(a) Senior unsecured revolving credit facilities

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

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

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

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

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

(b) Senior unsecured bank credit facilities

On December 30, 2016, in connection with the acquisition of Empire (note 3(a)), the Company drew U.S. $1,336,440 from the acquisition facility it obtained from a syndicate of banks earlier in 2016. The non-revolving term credit facilities are comprised of a U.S.$1,065,000 debt facility and a U.S.$271,440 equity facility both repayable in full on December 30, 2017. The funds drawn were transferred to a paying agent on December 30, 2016 for purposes of distribution to holders of the common shares of Empire (note 3(a)) on January 1, 2017. The total amount of cash held by the paying agent of U.S.$1,495,774 is comprised

of this acquisition facility draw of U.S. $1,336,440 and cash proceeds received from the initial instalment of convertible debentures (note 14) and is presented as restricted cash on the consolidated balance sheets. Subsequent to year end, on February 7, 2017, upon receipt of the Final Instalment from the Debentures (note 14) the Company repaid U.S. $567,650 under the acquisition Facility.

## 9. Long-term debt (continued)

(b) Senior unsecured bank credit facilities (continued)

On January, 4, 2016, the Company. entered into a U.S. $235,000 term credit facility with two U.S. banks. The term credit facility is available for acquisitions and general corporate purposes and matures on July 5, 2018.

As part of the Park Water System' s acquisition on January 8, 2016 (note 3(e)), the Company assumed U.S. $22,500 of debt outstanding under a non-revolving term credit facility. The term credit facility bears a variable interest rate based on LIBOR plus a credit spread and matures in 2019 but is repayable on demand without penalty.

(c) Canadian dollar senior unsecured notes

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

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

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

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

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

(e) U.S. dollar senior secured notes

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

(f) U.S. Senior Secured Utility Bonds

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

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

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

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

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

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

## 10. Pension and other post-employment benefits

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

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

(a) Net pension and OPEB obligation

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

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

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

(a) Net pension and OPEB obligation (continued)

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

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

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

(b) Assumptions

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

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

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

(b) Assumptions (continued)

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

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

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

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

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

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

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

(c) Benefit costs

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

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

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

(d) Plan assets

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

The Company's target asset allocation is as follows:

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

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

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

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

(e) Cash flows

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

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

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

## 11. Mandatorily redeemable Series C preferred shares

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

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

## 11. Mandatorily redeemable Series C preferred shares (continued)

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

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

## 12. Other assets

Other assets consist of the following:

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

## 13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

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

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

(a) Advances in aid of construction

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

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

(b) Environmental remediation obligation

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

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

Changes in the environmental remediation obligation are as follows:

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

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

(c) Asset retirement obligations

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

(d) Customer deposits

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

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

(e) Deferred income

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

(f) Deferred credits

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

## 14. Convertible Unsecured Subordinated Debentures

| | | |
|---|---|---|
| Maturity date | | March 31, 2026 |
| Interest rate | | 5.00% |
| Conversion price per share | $ | 10.60 |
| Carrying value at December 31, 2015 | $ | — |
| Receipt of initial instalment, net of deferred financing costs | | 357,694 |
| Amortization of deferred financing costs | | 925 |
| Carrying value at December 31, 2016 | $ | 358,619 |
| Face value at December 31, 2016 | $ | 382,950 |

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

The convertible debentures were sold on an instalment basis at a price of $1,000 principal amount of debenture, of which $333 was received on closing of the debenture offering and the remaining $667 (the “Final Instalment”) is receivable on a date (“Final Instalment Date”) to be fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial instalment were $382,950. The Company incurred deferred financing costs of $25,255, which are being amortized to interest expense over 10 years, the contractual term of the convertible debentures, using the effective interest rate method.

The convertible debentures represented by the initial instalment receipt are classified as a non-current liability on the consolidated balance sheets as settlement in cash is not expected to occur within 12 months. The convertible debentures mature on March 31, 2026 and bear interest at an annual rate of 5% per $1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate will be 0%. The interest expense recorded is $48,205 (2015 - $nil).

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

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

After the Final Instalment Date, any debentures not converted into common shares may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

## 15. Shareholders' capital

(a) Common shares

Number of common shares:

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

**Authorized**

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

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

(i) Public offering

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

(ii) Subscription receipts

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

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

(iii) Dividend reinvestment plan

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

## 15. Shareholders' capital (Continued)

(b) Preferred shares

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

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

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

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

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

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

(c) Share-based compensation

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

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

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

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

## 15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan

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

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

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

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

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

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

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

## 15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

Share option activity during the years is as follows:

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

(ii) Employee share purchase plan

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

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

(iii) Directors deferred share units

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

## 15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance share units

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

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

A summary of the PSUs follows:

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

## 16. Accumulated Other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

| | Foreign currency cumulative translation | Unrealized gain on cash flow hedges | Net change on available-for-sale investments | Pension and post-employment actuarial changes | Total |
|---|---|---|---|---|---|
| Balance, January 1, 2015 | $ 32,496 | $ 23,164 | $ 1 | $ (21,448) | $ 34,213 |
| OCI (loss) before reclassifications | 228,861 | 21,896 | (73) | 6,487 | 257,171 |
| Amounts reclassified | — | (5,731) | — | 1,084 | (4,647) |
| Net current period OCI | 228,861 | 16,165 | (73) | 7,571 | 252,524 |
| Balance, December 31, 2015 | $ 261,357 | $ 39,329 | $ (72) | $ (13,877) | $ 286,737 |
| OCI before reclassifications | (61,029) | 34,308 | 213 | 1,648 | (24,860) |
| Amounts reclassified | — | (7,554) | — | 604 | (6,950) |
| Net current period OCI | $ (61,029) | $ 26,754 | $ 213 | $ 2,252 | $ (31,810) |
| Balance, December 31, 2016 | $ 200,328 | $ 66,083 | $ 141 | $ (11,625) | $ 254,927 |

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

## 17. Dividends

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

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

## 18. Related party transactions

*Emera Inc.*

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

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

## 18. Related party transactions (continued)

*Equity-method investments*

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $3,313 (2015 - $2,021) during the year.

*Trafalgar*

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

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

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

*Long Sault Hydro Facility*

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

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

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

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

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

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

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

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

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

Changes in redeemable non-controlling interest are as follows:

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

## 20. Income taxes

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

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

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

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

## 20. Income taxes (continued)

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

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

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

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

## 20. Income taxes (continued)

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

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

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

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

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

## 21. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and subscription receipts outstanding (note 15 (a)(ii)). Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

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

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

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

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

## 22. Segmented information

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

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

As at December 31, 2016, APUC has three reporting segments: Generation, Transmission and Distribution.The Transmission segment is not significant and as a result is not presented separately in the tables below but grouped within Corporate.

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

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

## 22. Segmented information (continued)

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

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

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

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

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

## 23. Commitments and contingencies

(a) Contingencies

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

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2016.

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

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Power purchase (i) | $ 63,330 | $ 36,622 | $ 37,398 | $ 38,822 | $ 38,822 | $ — | $ 214,994 |
| Gas supply and service agreements (ii) | 62,179 | 45,468 | 37,407 | 31,636 | 17,400 | 64,284 | 258,374 |
| Service agreements | 41,446 | 42,252 | 42,508 | 45,178 | 46,019 | 503,671 | 721,074 |
| Capital projects | 66,696 | 19,538 | 69 | 69 | 69 | 17 | 86,458 |
| Operating leases | 7,342 | 6,851 | 6,519 | 6,403 | 6,480 | 123,604 | 157,199 |
| Total | $ 240,993 | $ 150,731 | $ 123,901 | $ 122,108 | $ 108,790 | $ 691,576 | $ 1,438,099 |

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

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

## 24. Non-cash operating items

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

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

## 25. Financial instruments

(a) Fair value of financial instruments

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

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

## 25. Financial instruments (continued)

(a)Fair value of financial instruments (continued)

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

## 25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

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

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

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

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

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $24.44 to $105.03 with a weighted average of $37.36 as of December 31, 2016. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 25(b)(ii) and 25(b)(iv).

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

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2016 and 2015.

(b) Derivative instruments

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

(i) Commodity derivatives – regulated accounting

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

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

| | 2016 |
|---|---|
| Financial contracts: Gas swaps | 384,999 |
| Gas options | 844,167 |
| | 1,229,166 |

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7(c)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

## 25. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

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

| | 2016 | 2015 |
|---|---|---|
| Regulatory assets: | | |
| Gas swap contracts | U.S. **$** **—** | U.S. $ 1,058 |
| Gas option contracts | U.S. **$** **27** | U.S. $ 154 |
| Regulatory liabilities: | | |
| Gas swap contracts | U.S. **$** **175** | U.S. $ 3 |
| Gas option contracts | U.S. **$** **92** | U.S. $ — |

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

| Notional quantity (MW-hrs) | Expiry | Receive average prices (per MW-hr) | Pay floating price (per MW-hr) |
|---|---|---|---|
| 686,340 | December 2022 | U.S. $ 42.81 | PJM Western HUB |
| 2,930,009 | December 2022 | U.S. $ 30.25 | NI HUB |
| 3,663,549 | December 2027 | U.S. $ 36.46 | ERCOT North HUB |

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

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

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

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

The Company expects $10,024 of unrealized gains currently in AOCI to be reclassified into non-regulated energy sales within the next twelve months, as the underlying hedged transactions settle.

## 25. Financial instruments (continued)

(b) Derivative instruments (continued)

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

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

The Company designates the amounts drawn on the Renewable Generation Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Renewable Generation Group's U.S. operations. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency loss of nil for the year ended December 31, 2016 (2015 - nil) was recorded in OCI.

Concurrent with its $150,000, $200,000 and $300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A gain of $2,189 (2015 - loss of $68,195) was recorded in OCI in 2016 for the December 2012 and January 2014 swaps.

(iv) Other derivatives

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

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

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 25(b)(ii)).

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

The Company is exposed to foreign exchange fluctuations related to U.S dollar denominated development loans from projects accounted for as equity investments (note 8(f)). This risk was mitigated through the use of currency forward contracts to sell U.S. $38,400 for $47,225 between July 29, 2016 and September 29, 2016. As of December 31, 2016, these instruments had settled. This currency forward contract was not accounted for as a hedge.

## 25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

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

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

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

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

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

(c) Risk management

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

## 25. Financial instruments (continued)

(c) Risk management (continued)

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

*Credit risk*

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders all of which have a credit rating of A or better. The Company does not consider the risk associated with the Renewable Generation Group accounts receivable to be significant as over 80% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of U.S.$100,417 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2016, the Company's maximum exposure to credit risk for these financial instruments was as follows:

| | December 31, 2016 | |
|---|---|---|
| | Canadian $ | US $ |
| Cash and cash equivalents and restricted cash | $ 16,874 | $ 1,578,704 |
| Accounts receivable | 14,571 | 135,660 |
| Allowance for doubtful accounts | — | (5,261) |
| Notes receivable | 31,406 | 5,048 |
| | $ 62,851 | $ 1,714,151 |

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

*Liquidity risk*

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2016, in addition to cash on hand of $110,417 the Company had $295,915 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

## 25. Financial instruments (continued)

(c) Risk management (continued)

*Liquidity risk (continued)*

The Company's liabilities mature as follows:

| | Due less than 1 year | Due 2 to 3 years | Due 4 to 5 years | Due after 5 years | Total |
|---|---|---|---|---|---|
| Long-term debt obligations | $ 1,871,864 | $ 745,301 | $ 304,890 | $ 979,210 | $ 3,901,265 |
| Convertible Debentures | — | — | — | 358,619 | 358,619 |
| Advances in aid of construction | 3,140 | — | — | 102,051 | 105,191 |
| Interest on long-term debt | 194,831 | 152,976 | 110,718 | 347,700 | 806,225 |
| Purchase obligations | 398,910 | — | — | — | 398,910 |
| Environmental obligation | 4,043 | 23,933 | 7,123 | 41,754 | 76,853 |
| Derivative financial instruments: | | | | | |
| Cross-currency swap | 4,144 | 7,660 | 49,358 | 34,242 | 95,404 |
| Interest rate swaps | — | 13,385 | — | — | 13,385 |
| Energy derivative and commodity contracts | 34 | 2 | — | — | 36 |
| Other obligations | 32,624 | — | — | 47,212 | 79,836 |
| Total obligations | $ 2,509,590 | $ 943,257 | $ 472,089 | $ 1,910,788 | $ 5,835,724 |

## 26. Comparative figures

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

**Exhibit 99.3**

ALGONQUIN Power & Utilities Corp.

# Management Discussion & Analysis

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

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

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

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

### Forward-looking Statements and Forward-Looking Information

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

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

### Non-GAAP Financial Measures

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

## Use of Non-GAAP Financial Measures

Adjusted EBITDA

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

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP, which can be impacted positively or negatively by these items.

Adjusted Funds from Operations

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

Net Energy Sales

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

Net Utility Sales

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

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative

expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. Where the Company manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

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

## Overview and Business Strategy

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

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

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

### Renewable Generation Group

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

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

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

### Liberty Utilities Group

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

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

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

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

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

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

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

# 2016 Major Highlights

## Corporate Highlights

**Completion of The Empire District Electric Company Acquisition**

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

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

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

APUC expects the Empire Acquisition will be accretive to earnings per common share in the first full year following closing and approximately 7% - 9% accretive to APUC's net earnings per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. APUC's increased contribution from regulated operations is also expected to further enhance the stability and predictability of the Company's Adjusted EBITDA, net earnings and quality of cash flows.

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

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

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

In addition to the completion of the Empire Acquisition in the first quarter of 2017, APUC has completed construction of new electric generating stations and has a number of electric generating stations in construction and under development. Collectively these growth initiatives have continued to raise the growth profile of the Company. As a result, on January 16, 2017, the Board approved a dividend increase of U.S. $0.0424 per common share annually, bringing the total annual dividend to U.S. $0.4659 per common share, an increase of 10% over the previous annual dividend rate.

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

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

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

**Strong Year of Operating Results**

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

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

**Completion of Financing Related to the Acquisition**

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

In the first quarter of 2016, in connection with the Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on

a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

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

*U.S. $750 Million Private Placement Offering*

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

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

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

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

**U.S. $235 Million Corporate Term Credit Facility**

On January 4, 2016, the Company entered into a U.S. $235.0 million term credit facility ("Corporate Term Facility") with two U.S. banks. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2018.

## Renewable Generation Group Highlights

**Acquisition of 75% interest in the Red Lily I Partnership**

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

**Completion of the Odell Wind Project**

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

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

**Completion of the Deerfield Wind Project**

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

**Completion of the Bakersfield II Solar Project**

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

**Issuance of $300 million Senior Unsecured Debentures**

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

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

**Purchase of Turbines to Safe Harbor Production Tax Credit Rate**

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

## Liberty Utilities Group Highlights

**Acquisition of the Park Water System**

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

Total consideration for the utility purchase was U.S. $341.3 million, which includes the assumption of approximately U.S. $91.8 million of existing debt. This acquisition maintains APUC's strategic business mix and further enhances its investment grade consolidated capital structure.

The water utility located in western Montana is currently the subject of a condemnation proceeding by the city of Missoula. (See "Regulatory Risk Section: *Condemnation Expropriation Proceedings"* for further discussion.)

**Completion of the Luning Solar Project.**

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

**Successful Rate Case Outcomes**

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

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

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

## 2016 Fourth Quarter Results From Operations

### Key Financial Information

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

[1] Non-GAAP Financial Measures.

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

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

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

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

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

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

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

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

## 2016 Annual Results From Operations

### Key Financial Information

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

1 Non-GAAP Financial Measures.

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

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

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

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

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

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

For the twelve months ended December 31, 2016 , net earnings attributable to shareholders totaled $130.9 million as compared to $117.5 million during the same period in 2015, an increase of $13.4 million. The increase was due to a $95.9 million increase in earnings from operating facilities, $1.5 million increase in interest, dividend, equity and other income, $3.5 million increase in Other Gains, $6.2 million decrease in losses on long lived assets, $13.7 million increase on gains from

derivative instruments, $6.6 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*), $1.0 million decrease in loss on discontinued operations, and $6.6 million increase in losses attributable to non-controlling interests. These items were partially offset by $37.1 million increase in depreciation and amortization expenses, $6.5 million increase in administration charges, $2.2 million decrease in foreign exchange gains, $65.6 million increase in interest expense and $10.2 million increase in acquisition costs as compared to the same period in 2015.

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

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

## 2016 Adjusted EBITDA Summary

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

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

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

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

## RENEWABLE GENERATION GROUP

### 2016 Electricity Generation Performance

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

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

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

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

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

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

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

[7] Natural gas fired co-generation facility.

## 2016 Fourth Quarter Generation Performance

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

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

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

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

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

## 2016 **Annual Generation** Performance

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

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

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

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

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

## 2016 Renewable Generation Group Operating Results

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

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

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

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

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

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

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

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

8 See Non-GAAP Financial Measures.

## 2016 Fourth Quarter Operating Results

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

Highlights of the changes are summarized in the following table:

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

## 2016 Annual Operating Results

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

Highlights of the changes are summarized in the following table:

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

## Development Division

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

The Renewable Generation Group's Development Division has successfully completed, is constructing, and is developing a number of power generation projects. The division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with credit-worthy counterparties, and meet or exceed the Company's investment return objectives. The projects are as follows:

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

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

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

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

## Projects Recently Completed

**Deerfield Wind Project**

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

Construction of the project commenced in the fourth quarter of 2015. The project declared commercial operations on February 21, 2017.

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

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

**Bakersfield II Solar Project**

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

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

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

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

## Projects in Construction

**Amherst Island Wind Project**

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

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

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

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

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

**Great Bay Solar**

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

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

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

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

## Projects in Development

**Chaplin-Blue Hill Wind Project**

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

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

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

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

**Val-Éo Wind Project**

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

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

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely be comprised of ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

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

## LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 565,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, Liberty Utilities completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. Including Empire, Liberty now serves approximately 783,000 customers. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

### Utility System Type

| | As at December 31 | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| (all dollar amounts in U.S. $ millions) | Assets | Total Connections[1] | Assets | Total Connections[1] |
| Electricity | **$ 378.4** | **94,000** | $ 343.2 | 93,000 |
| Natural Gas | **845.9** | **293,000** | 783.0 | 292,000 |
| Water and Wastewater | **516.4** | **178,000** | 254.7 | 104,000 |
| **Total** | **$ 1,740.7** | **565,000** | $ 1,380.9 | 489,000 |
| Accumulated Deferred Income Taxes Liability | **$ 194.7** | | $ 110.3 | |

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

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

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 94,000 connections in the states of California and New Hampshire.

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

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

### 2016 Fourth Quarter Usage Results

### Electric Distribution Systems

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

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

## Natural Gas Distribution Systems

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

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

## Water and Wastewater Distribution Systems

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

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

## 2016 Fourth Quarter Operating Results

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

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

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

Highlights of the changes are summarized in the following table:

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

## 2016 **Annual** Usage Results

### Electric Distribution Systems

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

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

## Natural Gas Distribution Systems

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

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

## Water and Wastewater Distribution Systems

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

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

## 2016 **Annual** Operating Results

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

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

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

Highlights of the changes are summarized in the following table:

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

## Regulatory Proceedings

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

| Utility | State | Regulatory Proceeding Type | Rate Request U.S. $ (millions) | Current Status |
|---|---|---|---|---|
| **Completed Rate Cases** | | | | |
| Peach State Gas System | Georgia | GRAM | $3.4 | Final Order issued in February 2016 approving a U.S. $2.7 million rate increase effective March 1, 2016. |
| New England Gas System | Massachusetts | General Rate Case | $11.8 | Final Order issued in February 2016 approving a U.S. $8.3 million rate increase, with U.S. $7.8 million effective March 1, 2016 and U.S. $0.5 million effective March 1, 2017. |
| Black Mountain Sewer System | Arizona | General Rate Case | $0.4 | Final Order issued in April 2016 approving U.S. $0.2 million rate increase effective May 1, 2016. |
| Rio Rico Water/Sewer System | Arizona | General Rate Case | $0.9 | Application filed in October 2015 seeking a U.S. $0.9 million revenue increase. A final permanent rate decision issued in October 2016 allowed for a U.S. $0.98 million revenue increase effective November 2016. |
| Bella Vista Water System | Arizona | General Rate Case | $1.6 | Application filed in October 2015 seeking a U.S. $1.6 million revenue increase. A final permanent rate decision issued in October 2016 allowed for a U.S. $0.96 million revenue increase effective November 2016. |
| CalPeco Electric System | California | General Rate Case | $13.6 | Application filed in May 2015 seeking a U.S. $13.6 million revenue increase (U.S. $11.4 million related directly to distribution margin) effective January 2016. A settlement agreement was filed in April 2016 and approved by the CPUC in December, 2016. The approved settlement authorized a U.S. $8.3 million margin revenue increase retroactive to Q1 2016. |
| Peach State Gas System | Georgia | GRAM | $0.6 | Application filed in October 2016 seeking a U.S. $0.6 million revenue increase. A final permanent rate decision was issued in January 2017 approving a U.S. $0.7 million increase, with new rates effective February 2017. |
| **Pending Rate Cases** | | | | |
| Entrada Del Oro | Arizona | General Rate Case | $0.3 | Application filed in March 2016 seeking a U.S. $0.3 million revenue increase. A final permanent rate decision is expected in Q2 2017. |
| Granite State Electric System | New Hampshire | General Rate Case | $7.7 | Application filed in April 2016 seeking a U.S. $7.7 million revenue increase. A temporary rate increase of U.S. $2.4 million became effective July 2016. A final permanent rate decision is expected in Q2 2017. |
| Illinois Gas System | Illinois | General Rate Case | $3.0 | A settlement was filed with the Illinois Commerce Commission ("ICC") which results in the establishment of a decoupling mechanism, bad debt tracker, and enhanced growth mechanism. The settlement will result in annualized revenue increases of $2.3 million and is expected to be implemented in July 2017. |
| Iowa Gas System | Iowa | General Rate Case | $1.1 | A settlement was filed with the Iowa Utilities Board ("IUB") in February 2017 which will result in an annualized revenue increase of U.S. $1.0 million, expected to become effective Q2 2017. A final permanent rate decision is expected in Q2 2017. |
| Woodmark/Tall Timbers Water & Wastewater Systems | Texas | General Rate Case | $2.0 | Application filed in September 2016 seeking a U.S. $2.0 million revenue increase. A final permanent rate decision is expected in Q4 2017. |

**Completed Rate Cases**

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

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

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

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

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

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

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

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

**Pending Rate Cases and Other Regulatory Applications**

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

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

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

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

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

**Park Water System Acquisition**

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

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

**The Empire District Electric Company Acquisition**

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

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

## APUC: CORPORATE AND OTHER EXPENSES

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

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

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

### 2016 Fourth Quarter Corporate and Other Expenses

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

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

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

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

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

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

### 2016 Annual Corporate and Other Expenses

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

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

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

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

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

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

# NON-GAAP PERFORMANCE MEASURES

## Reconciliation of Adjusted EBITDA to Net Earnings

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

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

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

## Reconciliation of Adjusted Net Earnings to Net Earnings

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## 2016 Fourth Quarter Property Plant and Equipment Expenditures

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

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

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

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

## 2016 Annual Property Plant and Equipment Expenditures

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

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

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

## 2017 Capital Investments

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

Expected 2017 capital investment ranges are as follows:

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

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, funds committed by tax equity investors, revolving credit facilities, as well as the debt and equity capital markets to finance its 2017 capital investments.

## LIQUIDITY AND CAPITAL RESERVES

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

### Bank Credit Facilities

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

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

As at December 31, 2016, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $12.1 million of outstanding letters of credit. The facility matures on November 19, 2017 and is subject to customary covenants.

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

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

As part of the Park Water System's acquisition on January 8, 2016, the Company assumed U.S. $22.5 million of debt outstanding under a non-revolving term credit facility. The term credit facility bears a variable interest rate based on LIBOR plus a credit spread and matures in 2019 but is repayable on demand without penalty.

On February 9, 2016, in connection with the acquisition of Empire, the Company obtained U.S. $1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. Upon receiving the initial instalment from the Debentures (described below), the Company reduced the commitments under the Acquisition Facility by U.S. $263.6 million. On December 30, 2016 the Company drew U.S. $1,336.4 million on the Acquisition Facility. The funds drawn were transferred to a paying agent for purposes of distribution to holders of the common shares of Empire (see note 3(a) on the Company's Audited Consolidated Financial Statements) on January 1, 2017. The Acquisition Facility matures on December 29, 2017

and is subject to an initial funding fee payment on March 30, 2017 calculated on the balance drawn on the that date. The Acquisition Facility is subject to margin step ups and duration fees that commence on March 30, 2017 and are calculated based on the amounts drawn.

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

## Long Term Debt

On January 4, 2016 a subsidiary of the Company entered into a U.S. $235.0 million term credit facility with two U.S. banks ("Corporate Term Facility"). The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2018, and is subject to customary covenants.

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

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

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

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

## Convertible Unsecured Subordinated Debentures

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

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

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

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

APUC will issue up to 108,490,556 common shares on conversion of all debentures. As at March 1, 2017, a total of 107,517,895 common shares of the company were issued, representing conversion into common shares of 99.1% of the convertible debentures. After the Final Instalment Date, any debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

## Credit Ratings

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

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

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

## Contractual Obligations

Information concerning contractual obligations as of December 31, 2016 is shown below:

| (all dollar amounts in $ millions) | Total | Due less than 1 year | Due 1 to 3 years | Due 4 to 5 years | Due after 5 years |
|---|---|---|---|---|---|
| Principal repayments on debt obligations[1] | **$ 3,901.3** | $ 1,871.9 | $ 745.3 | $ 304.9 | $ 979.2 |
| Convertible debentures | **358.6** | — | — | — | 358.6 |
| Advances in aid of construction | **105.2** | 3.1 | — | — | 102.1 |
| Interest on long-term debt obligations | **806.2** | 194.8 | 153.0 | 110.7 | 347.7 |
| Purchase obligations | **398.9** | 398.9 | — | — | — |
| Environmental obligations | **76.8** | 4.0 | 23.9 | 7.1 | 41.8 |
| Derivative financial instruments: | | | | | |
| Cross currency swap | **95.4** | 4.1 | 7.7 | 49.4 | 34.2 |
| Interest rate swap | **13.4** | — | 13.4 | — | — |
| Purchased power | **214.9** | 63.3 | 74.0 | 77.6 | — |
| Gas delivery, service and supply agreements | **258.4** | 62.2 | 82.9 | 49.0 | 64.3 |
| Service agreements | **721.1** | 41.4 | 84.8 | 91.2 | 503.7 |
| Capital projects | **86.4** | 66.7 | 19.6 | 0.1 | — |
| Operating leases | **157.2** | 7.3 | 13.4 | 12.9 | 123.6 |
| Other obligations | **79.8** | 32.6 | — | — | 47.2 |
| **Total Obligations** | **$ 7,273.6** | **$ 2,750.3** | **$ 1,218.0** | **$ 702.9** | **$ 2,602.4** |

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

## Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2016, APUC had 274,087,018 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any

remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

On February 9, 2016, in connection with the acquisition of Empire, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.0 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures of APUC. On March 9, 2016, the Underwriters exercised their option to purchase an additional $150.0 million of Debentures, bringing the total amount of Debentures under the Debenture Offering to $1.15 billion.

All Debentures were sold on an instalment basis at a price of $1,000 dollars per Debenture, of which $333 dollars was paid on the closing of the Offering and the remaining $667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of APUC's acquisition of Empire. On the Final Instalment Date each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

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

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2016, APUC had outstanding:

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

APUC has a shareholder dividend reinvestment plan (the “Reinvestment Plan”) for registered holders of common shares of APUC. As at December 31, 2016, 61,419,484 common shares representing approximately 22% of total common shares outstanding had been registered with the Reinvestment Plan. During the quarter ended December 31, 2016, 725,171 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 13, 2017, an additional 823,738 common shares were issued under the Reinvestment Plan.

## SHARE BASED COMPENSATION PLANS

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

As at December 31, 2016, total unrecognized compensation costs related to non-vested options and share unit awards were $3.2 million and $2.2 million, respectively, and are expected to be recognized over a period of 1.77 and 1.74 years, respectively.

### Stock Option Plan

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

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options’ vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the twelve months ended December 31, 2016, the Company granted 2,596,025 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $10.85, the market price of the underlying common share at the date of grant. In March 2016, executives of the Company exercised 3,715,663 stock options at a weighted average exercise price of $5.25 in exchange for 2,720,980 common shares issued from treasury and 994,683 shares withheld as payment in lieu of minimum tax withholdings.

As at December 31, 2016, a total of 6,045,014 options are issued and outstanding under the plan.

### Performance Share Units

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

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

### Directors Deferred Share Units

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

As at December 31, 2016, a total of 224,663 DSUs had been granted under the DSU plan.

### Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the twelve months ended December 31, 2016, the Company issued 144,264 common shares to employees under the ESPP.

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

## MANAGEMENT OF CAPITAL STRUCTURE

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

APUC's objectives when managing capital are:

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

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

## RELATED PARTY TRANSACTIONS

**Emera Inc.**

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

for professional services incurred and accrued in 2014.

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

**Equity-method investments**

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $3.3 million as compared to $2.0 million during the same period in 2015.

**Trafalgar**

The Company owned debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Trafalgar went into default under its debt obligations and an entity partially and indirectly owned by Senior Executives (the "Related Entity"), moved to foreclose on the assets on behalf of the Company. Subsequent to the foreclosure action, Trafalgar went into bankruptcy. APUC and the Related Entity have jointly pursued litigation and bankruptcy proceedings with Trafalgar since 2002.

In 2003 and 2004, the Company reimbursed the Related Entity $1.0 million of the approximately $2.0 million in third-party legal fees it had initially funded and APUC agreed to fund future legal fees and other liabilities. It was agreed that any net proceeds from the litigation and bankruptcy proceedings would be shared proportionally to the quantum of net legal costs funded by each party.

On June 30, 2016, the Company received U.S. $10.1 million in proceeds from the settlement of this matter and, subsequent to quarter-end, paid U.S. $2.9 million to the Related Entity as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in the second quarter of 2016.

**Long Sault Hydro Facility**

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. (“APC”) which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2017.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

# ENTERPRISE RISK MANAGEMENT

An enterprise risk management ("ERM") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC’s ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by APUC’s internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops as well as APUC's "Risk Insights" program which provides all employees with a mechanism to communicate risks and opportunities at any time. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and presented to the Board of Directors’ Risk Committee. The key risk categories assessed include: safety, environment, natural disasters, compliance, security (physical and cyber), financial reporting, operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

Risks are assessed consistently across the organization using a common risk scoring matrix to assess impact and likelihood. Financial, reputation, and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of APUC’s strategic and business plans.

The development and execution of risk treatment plans for the organization's top risks are actively monitored by the Executive team. APUC’s internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and reported to the Audit Committee of the Board. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, the Executive team, and the Board of Directors for consideration.

APUC’s ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust and that APUC’s risk appetite is thoroughly considered in decision-making across the organization.

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries’ business risks is also set out in the most recent AIF.

## Treasury Risk Management

**Foreign Currency Risk**

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars.

Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 84% of EBITDA in 2016 and 83% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $40.0 million ($0.16 per share) on an annual basis.

In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs.

Although APUC may enter into derivative contracts to hedge currency exchange rate exposure, the Company typically does not hedge its full exposure. To the extent that the Company does enter into currency hedges, the Company will not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts

The $1.15 billion of convertible debentures raised in the first quarter of 2016 to fund the acquisition of Empire were denominated in Canadian dollars. In order to mitigate the effects of a potential funding mismatch due to fluctuations in the foreign exchange rate, over the course of 2016 the Company converted the total expected proceeds into U.S. dollars by purchasing spot and forward currency exchange contracts with an average U.S. exchange rate of approximately $1.3282. Hedge accounting was not applicable, hence changes in value of the forward contracts have been recorded in the Company's Statement of Operations.

**Market Price Risk**

The Renewable Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Renewable Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Renewable Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Renewable Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the group along with residual exposures to the market are detailed below:

On May 15, 2012, the Renewable Generation Group entered into a financial hedge, which expired December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge was structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. Starting in 2017, the unhedged production based on long term projected averages is approximately 65,000 MW-hrs annually. Therefore, each U.S. $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. $0.7 million on an annualized basis.

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $0.4 million for the year.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 million for the year.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Renewable Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2016, the Renewable Generation Group had not entered into any such short-term derivative contracts.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $0.5 million for the year.

**Credit/Counterparty Risk**

APUC and its subsidiaries through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Company.

Approximately 94% of the Renewable Generation Group's revenues are earned from large utility customers having a credit rating of Baa1 or better by Moody's Rating Services, or BBB or higher by S&P Rating Services, or BBB or higher by DBRS. The following chart sets out the Renewable Generation Group's customers representing greater than 5% of total revenues and their credit ratings and percentage of total revenue associated with the customer:

| Counterparty | Credit Rating [1] | Approximate Annual Revenues | Percent of Revenue |
|---|---|---|---|
| PJM Interconnection LLC | Aa2 | $ 32.2 | 13.2% |
| Ontario Electricity Financial Corporation | Aa2 | 29.7 | 12.2% |
| Manitoba Hydro | A | 28.7 | 11.8% |
| Hydro Quebec | Aa2 | 27.5 | 11.3% |
| Commonwealth Edison | Baa1 | 25.0 | 10.3% |
| Pacific Gas and Electric Company | A3 | 22.6 | 9.3% |
| Electric Reliability Council of Texas (ERCOT) | Aa3 | 17.4 | 7.2% |
| Connecticut Light and Power | Baa1 | 14.3 | 5.9% |
| **Total** | | **$ 197.4** | |

[1] Ratings by Moody's , Standard & Poor's, or DBRS.

The remaining revenue of the company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $16.1 million which is spread over approximately 178,000 connections, resulting in an average outstanding balance of approximately $90 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $46.8 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $21.1 million. The natural gas and electrical utilities both derive over 86% of their revenue from residential customers.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Company. Losses from a utility customer may not be fully compensated through bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement with the Renewable Generation Group is unable to perform, the Renewable Generation Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

**Interest Rate Risk**

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Generation Credit Facility is subject to a variable interest rate and had $242.9 million outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $2.4 million annually;
- The Liberty Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Acquisition Facility is subject to a variable interest rate and had $1,794.4 million (U.S. $1,336.4 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $17.9 million annually;
- The Corporate Term Facility is subject to a variable interest rate and had $315.5 million (U.S. $235.0 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $3.2 million annually;
- The Park Water System term credit facility is subject to a variable interest rate and had $30.2 million (U.S. $22.5 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually; and

- To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings.
    - In the fourth quarter of 2014, the Renewable Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.
    - On October 25, 2016, the Company entered into forward contracts to purchase U.S. $250.0 million 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250.0 million 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500.0 million bonds in relation to the acquisition of Empire (note 3(a)). Subsequent to year-end, the Company entered into a note purchase agreement to issue U.S. $750 million of notes with a weighted average coupon of 4.0% based on pricing established on January 27, 2017 (note 9(c)). Concurrent with the pricing of the notes, the Company also settled the open forward contracts on January 27, 2017, resulting in an effective interest rate on the bond offering of approximately 3.6%. Hedge accounting will apply to the effective portion of the realized gain on the hedge, while the ineffective portion of approximately U.S. $0.6 million will be recorded in income in the first quarter of 2017.

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

**Tax Risk and Uncertainty**

APUC is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which we do business could adversely affect APUC's results from operations, our return to shareholders, and cash flow. The Company endeavors to take tax positions that are sustainable, however, there can be no assurance that the tax positions taken by the Company will not be subject to challenge by the Canada Revenue Agency ('CRA") or the IRS. A successful challenge by either agency could impact our return to shareholders.

There is the potential for changes to the U.S. tax code (Internal Revenue Code or "IRC"). It is not possible to know what change to the IRC, if any, will be enacted in the U.S., and therefore, it is not possible to know what effect the changes, if any, might have on the Company. There can be no assurance that any changes to the U.S. IRC would not impact the Company's tax-related assets, liabilities, and expense which could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Development by the Renewable Generation Group of renewable power generation facilities in the United States is dependent in part on federal tax credits and other tax incentives, the availability of which requires that construction of the applicable facility be commenced by a statutory deadline. While these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down in the amount of the incentives. There can be no assurance that reduced incentive levels will be sufficient to support continued development and construction of renewable power facilities in the United States, nor that the applicable legislation will not be further limited. In addition, the Renewable Generation Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

**Liquidity Financing Risk**

As of December 31, 2016, the Company had approximately $4,272.0 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

The ability of the Company to raise additional debt or equity or to do so on favorable terms may be affected by the Company's financial and operational performance, and by financial market disruptions or other factors outside the control of the Company.

In addition, the Company may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the degree of the Company's leverage could, among other things, limit the Company's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Company's flexibility and discretion to operate its business; limit the Company's ability to declare dividends on its Common Shares; require the Company to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Company's existing credit ratings; expose the Company to increased interest expense on borrowings at variable rates; limit the Company's ability to adjust to changing market conditions; place the Company at a

competitive disadvantage compared to its competitors that have less debt; make the Company vulnerable to any downturn in general economic conditions; and render the Company unable to make expenditures that are important to its future growth strategies.

The Company will need to refinance or reimburse amounts outstanding under the Company's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favorable than the current terms, the ability of the Company to declare dividends may be adversely affected.

The ability of the Company to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Company, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and future capital expenditure requirements. In addition, the ability of the Company to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Company and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Company would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

**Downgrade in the Company's Credit Rating Risk**

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). APCo has a BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing entity of Liberty Utilities Co has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long term debt securities issued. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

**Commodity Price Risk**

The Renewable Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 164,000 MW-hrs in fiscal 2017, of which 133,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 25,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 164,000 MW-hrs. The risk associated with the expected market purchases of 25,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 78% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $83 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.1 million on an annualized basis.

The CalPeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. The CalPeco Electric System also benefits from a revenue decoupling mechanism and a vegetation management memorandum account. The revenue decoupling mechanism decouples base revenues from fluctuations caused by weather and economic factors reducing volumetric risk for the utility. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility, reducing the potential for expenses to exceed the amounts allowed for in general rates.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the New Hampshire Public Utilities Commission ("NHPUC") on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth

Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved

rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia PSC for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 54% of its 2016 generation fuel supply need through coal. Approximately 97% of its 2016 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts satisfy approximately 92% of anticipated fuel requirements for 2017 and 23% for 2018 for the Asbury Coal Facility. In order to manage exposure to fuel prices, future coal supplies will be acquired using a combination of short-term and long-term contracts.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel accommodation clause and PGA filings and are embedded in the approved rates in such filings.

## OPERATIONAL RISK MANAGEMENT

**Regulatory Risk**

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Renewable Generation Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Liberty Utilities Group regularly works with its governing authorities to manage the affairs of the business, employing both local, state level, and corporate resources.

*Condemnation Expropriation Proceedings*

The Liberty Utilities Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require fair compensation to be paid. Determination of such fair compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value.

On January 8, 2016, the Company announced it had acquired Western Water Holdings LLC, which is the parent company of the regulated water distribution utility Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("Liberty Park Water"). Liberty Park Water owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and parts of western Montana. Mountain Water Company is the water utility in western Montana serving customers in and around the municipality of Missoula. Liberty Utilities (Apple Valley Ranchos Water) Corp. (“Liberty Apple Valley”). formerly known as Apple Valley Ranchos Water Co., is the water utility serving customers in and around the town of Apple Valley, California.

Mountain Water is currently the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court’s decision that the city of Missoula can proceed with condemnation of Mountain Water’s assets. Upon taking possession of Mountain Water’s assets, the compensation to be paid by the city of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. $88.6 million as of May 6, 2014). Mountain Water is expected to receive certain additional amounts that may include legal fees, interest, post-valuation capital expenditures and property tax reimbursement.

On December 22, 2015, various developers filed a lawsuit in Missoula County District Court against Mountain Water and the city of Missoula. The lawsuit pertains to Funded By Other (FBO) contracts between each developer and Mountain Water. Under these FBO contracts, the developers paid for facilities to provide water service and Mountain Water agreed to refund such amounts over a 40 year period. As of the date of acquisition of Western Water Holdings, the outstanding balance of these advances, on a non-discounted basis, was U.S. $23.1 million. On February 21, 2017, the court issued an order imposing equitable liens on the Mountain Water assets that are the subject of the FBO contracts, mandating that the liens be satisfied directly from the condemnation award, if and when paid.

APUC expects that, in light of the foregoing and agreements entered in to at the time of the acquisition, the net amount to be recognized by APUC in connection with the conclusion of all such proceedings is reasonably likely to be at least $103 million. However, such amount remains uncertain in light of outstanding legal issues and proceedings and, as a result, no assurances can be given as to such amount.

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the assets of Liberty Apple Valley. Liberty Apple Valley filed a response to the condemnation complaint on February 23, 2016. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases; initially to determine the necessity of the taking, and then, if the Town of Apple Valley is successful in the right to take proceeding, a second phase is held to determine the fair market value of the assets to be taken. The matter is expected to take two to three years to resolve. The condemnation action could have potential adverse financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Liberty Apple Valley’s assets by a jury if so elected by either party, along with a determination of interest and attorney’s fees by the court.

**Cycles and Seasonality**

Renewable Generation Group

The Renewable Generation Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily “run-of-river” and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies, impacting the amount of power that can be generated in a year.

The Renewable Generation Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the spring and fall periods, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Renewable Generation Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Liberty Utilities Group

The Liberty Utilities Group’s demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Liberty Utilities Group’s demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

The Liberty Utilities Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in

any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

**Development and Construction Risk**

The Company actively engages in the development and construction of new power generation facilities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Company's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

The Company mitigates these risks through its due diligence processes, sound project management practices and appropriate contingency plans and reserves.

*Risks Specific to Renewable Generation Projects*:

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Company relies on financing from third party tax equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

**Litigation Risks and Other Contingencies**

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

*Trafalgar Proceedings*

Trafalgar commenced an action in 1999 in U.S. District Court against the Company and various affiliates in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Company and various affiliates and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York ("Trafalgar Hydro Facilities"). Over the past 16 years, there have been various District Court adversary proceedings and bankruptcy proceedings in connection with this matter.

By the end of July, 2015, the Trafalgar Hydro Facilities were all sold with the Bankruptcy Court's approval.

In June, 2016, all of the above legal proceedings were settled pursuant to the terms outlined in the United States Bankruptcy Court for the Northern District of New York Order Approving Terms of Settlement which was entered into Bankruptcy Court on June 20, 2016. Pursuant to the Global Settlement, U.S. Bank was allowed U.S. $1.5 million. The Company and various affiliates were awarded approximately U.S. $10.1 million, amounts of which were received on June 30, 2016 (the "Litigation Proceeds"). The Litigation Proceeds were dispersed as more particularly outlined in MDA for the nine month period ending September 30, 2016 - Related Party Transactions.

*Long Sault Global Adjustment Claim*

In December 2012, N-R Power and Energy Corp., Algonquin Power (Long Sault) Partnership and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the GA as a price escalator. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011 onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court's judgment of March 12, 2015. The appeal was heard on December 14 and December 15, 2015. The Ontario Court of Appeal dismissed the OEFC's appeal by judgment dated April 19, 2016. OEFC sought leave to appeal to the Supreme Court of Canada (the "SCC"). In addition, OEFC brought a motion to stay the payment of the retroactive payments pending its appeal to the SCC. On August 5, 2016, the Court of Appeal denied OEFC's motion for a stay. On September 13, 2016, the Ontario Court of Appeal dismissed the motion brought by the OEFC to set aside or vary the order. On October 21, 2016, the OEFC made retroactive payments of $5.1 million and $0.3 million of interest to Long Sault. On January 19, 2017, the SCC denied OEFC's application for leave to appeal.

*Côte Ste-Catherine Water Lease Dues*

In October 2011, the Québec Court of Appeal ordered Mont-Laurier Partnership, a subsidiary of the Company, to pay approximately $5.4 million (including interest) to the Government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management of the Company believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6.9 million. In 2012, a subsidiary of the Company paid $1.9 million to the Government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interest on any amount ultimately determined to be payable or recoverable. The parties continue to engage in settlement discussions with a view to resolving this matter.

## QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended December 31, 2016:

| (all dollar amounts in $ millions except per share information) | 1st Quarter 2016 | 2nd Quarter 2016 | 3rd Quarter 2016 | 4th Quarter 2016 |
|---|---|---|---|---|
| Revenue | $ 341.7 | $ 222.8 | $ 221.3 | $ 310.2 |
| Net earnings / (loss) attributable to shareholders from continuing operations | 42.0 | 24.8 | 17.7 | 46.3 |
| Net earnings / (loss) attributable to shareholders | 42.0 | 24.8 | 17.7 | 46.3 |
| Net earnings / (loss) per share from continuing operations | 0.15 | 0.08 | 0.06 | 0.16 |
| Net earnings / (loss) per share | 0.15 | 0.08 | 0.06 | 0.16 |
| Adjusted Net Earnings | 56.1 | 30.9 | 26.6 | 51.4 |
| Adjusted Net Earnings per share | 0.21 | 0.11 | 0.09 | 0.18 |
| Adjusted EBITDA | 147.9 | 99.2 | 91.4 | 138.3 |
| Total assets | 5,615.5 | 5,555.0 | 6,020.8 | 8,249.5 |
| Long term debt[1] | 2,214.5 | 2,199.9 | 2,380.8 | 4,272.0 |
| Dividend declared per common share | $ 0.13 | $ 0.14 | $ 0.14 | $ 0.14 |

| | 1st Quarter 2015 | 2nd Quarter 2015 | 3rd Quarter 2015 | 4th Quarter 2015 |
|---|---|---|---|---|
| Revenue | $ 381.9 | $ 196.2 | $ 189.6 | $ 260.3 |
| Net earnings / (loss) attributable to shareholders from continuing operations | 43.1 | 20.6 | 16.7 | 38.1 |
| Net earnings/(loss) attributable to shareholders | 43.1 | 19.9 | 16.5 | 38.0 |
| Net earnings / (loss) per share from continuing operations | 0.16 | 0.07 | 0.06 | 0.14 |
| Net earnings/(loss) per share | 0.16 | 0.07 | 0.05 | 0.14 |
| Adjusted Net Earnings | 42.6 | 22.2 | 17.3 | 39.7 |
| Adjusted Net Earnings per share | 0.17 | 0.08 | 0.06 | 0.15 |
| Adjusted EBITDA | 114.5 | 81.1 | 70.2 | 109.6 |
| Total assets | 4,531.4 | 4,396.5 | 4,759.0 | 4,991.7 |
| Long term debt[1] | 1,482.7 | 1,440.3 | 1,613.3 | 1,486.8 |
| Dividend declared per common share | $ 0.11 | $ 0.12 | $ 0.13 | $ 0.13 |

[1] Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $189.6 million and $381.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $16.5 million and net earnings of $46.3 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

## DISCLOSURE CONTROLS

As of December 31, 2016, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2016, APUC's disclosure controls and procedures are effective.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

During the year ended December 31, 2016, APUC acquired the Park Water Facility. The financial information for this acquisition is included in this MD&A and in note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded this acquisition from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2016 due to the complexity associated with assessing internal controls during integration efforts.

For the twelve months ended December 31, 2016, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired business discussed above.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2016 based on the criteria set forth in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2016.

## CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its audited consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies and new accounting standards are discussed in notes 1 and 2 to the consolidated financial statements, respectively. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

### Estimated Useful Lives and Recoverability of Long-Lived Assets, Intangibles and Goodwill

The Company makes judgments a) to determine the recoverability of a development project, and the period over which the costs are capitalized during the development and construction of the project, b) to assess the nature of the costs to be capitalized, c) to distinguish individual components and major overhauls, and d) to determine the useful lives or unit-of-production over which assets are depreciated.

Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process.

The carrying value of long-lived assets, including intangible assets and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill. Some of the factors APUC considers as indicators of impairment include a significant change in operational or financial performance, unexpected outcome from rate orders, natural disasters, energy pricing and changes in regulation. When such events or circumstances are present, the Company assesses whether the carrying value will be recovered through the expected future cash flows. If the facility includes goodwill, the fair value of the facility is compared to its carrying value. Both methodologies are sensitive to the forecasted cash flows and in particular energy prices, long-term growth rate and, discount rate for the fair value calculation.

A recoverability analysis was performed in 2016 for wind and hydro generating assets operating without a PPA and in 2015 for certain small hydro generating facilities. No impairment provision was required in 2016 (2015 - $1.1 million). A quantitative assessment of goodwill performed as at September 30, 2014 concluded that the fair value of each reporting unit substantially exceeded their carrying value. In 2016 and 2015, Management performed a qualitative assessment for each of the eleven reporting units that were allocated goodwill. No goodwill impairment provision was required.

## Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements.

## Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Liberty Utilities Group's operations.

Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

## Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

## Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management’s judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management’s judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets obtained from external parties adjusted for nonperformance risk. A significant change in estimate could affect APUC’s results of operations if the hedging relationship was considered no longer effective.

## Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2016) recently released by the Society of Actuaries adjusted to reflect the 2016 Social Security Administration ultimate improvement rates.

**Sensitivities**

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2016 are outlined in the following table. They are calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and method used to prepare the sensitivity analysis has not changed

from previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized in the consolidated financial statements.

| (all dollar amounts in $ millions) | 2016 Pension Plans | | 2016 OPEB Plans | |
|---|---|---|---|---|
| | Accrued Benefit Obligation | Net Periodic Pension Cost | Accumulated Postretirement Benefit Obligation | Net Periodic Postretirement Benefit Cost |
| Discount Rate | | | | |
| 1% increase | (32.8) | (1.6) | (10.2) | (0.9) |
| 1% decrease | 40.0 | 2.7 | 12.8 | 0.8 |
| Future compensation rate | | | | |
| 1% increase | 0.2 | 0.9 | — | — |
| 1% decrease | (0.2) | (1.2) | — | — |
| Expected return on plan assets | | | | |
| 1% increase | — | (2.1) | — | (0.2) |
| 1% decrease | — | 2.1 | — | 0.2 |
| Life expectancy | | | | |
| 1% increase | 20.9 | 2.6 | 7.3 | 0.8 |
| 1% decrease | (22.4) | (2.6) | (6.9) | (1.0) |
| Health care trend | | | | |
| 1% increase | — | — | 11.3 | 1.5 |
| 1% decrease | — | — | (9.4) | (1.4) |

## Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management’s estimates and certain assumptions generally included in a present value calculation of the related cash flows.

Acquired assets and liabilities assumed that are subject to critical estimates include regulated property, plant and equipment, regulatory assets and liabilities, long-term debt and pension and OPEB obligations. The fair value of regulated property, plant and equipment is assessed using an income approach where the estimated cash flows of the assets are calculated using the approved tariff and discounted at the approved rate of return. The fair value of regulatory assets and liabilities considers the estimated timing of the recovery or refund to customers through the rate making process. The fair value of long-term debt is determined using a discounted cash flow method and current interest rates. The pension and OPEB obligations are valued by external actuaries using the guidelines of ASC 805, Business combinations.

Additional disclosure of APUC’s critical accounting estimates is also available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

**Exhibit 99.4**

**Consent of Independent Registered Public Accounting Firm**

We consent to the reference to our Firm under the captions “Interest of 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 March 10, 2017, with respect to the consolidated balance sheets of Algonquin Power and Utilities Corp. (the “Company”) as at December 31, 2016 and 2015, and the consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the two-year period ended December 31, 2016, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2016.

We also consent to the incorporation by reference of our reports dated March 10, 2017 in the Registration Statements on Form S-8 (No. 333-177418), Form S-8 (File No. 333-213650), and Form S-8 (File No. 333-213648) of our reports dated March 10, 2017, with respect to the consolidated balance sheets of the Company as at December 31, 2016 and 2015, and the consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the two-year period ended December 31, 2016, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2016.

*/s/ "Ernst & Young, LLP"*

Toronto, Canada
March 10, 2017

Chartered Professional Accountants,
Licensed Public Accountants



A member firm of Ernst & Young Global Limited

**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: March 10, 2017

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: March 10, 2017

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, 2016 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: March 10, 2017

By: /s/ Ian 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, 2016 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: March 10, 2017

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer