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, 2014 **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
N/A	N/A

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.

N/A
(Title of Class)

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, 2014, there were 238,149,468 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 proceeding 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 in the past 90 days.

Yes x **No** o

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, 2014 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, 2014 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, 2014 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 59) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2014, 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, 2014, 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 at December 31, 2014.

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, 2014, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2014.

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, 2014, 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 59) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2014, 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 three audit committee financial experts serving on its audit committee. Christopher Ball, Kenneth Moore 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, Kenneth Moore 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, Kenneth Moore 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 and Chief Accounting Officer. The Code of Conduct is available without charge to any shareholder upon request to Kelly Castledine, 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 81) in the Annual Information Form for the fiscal year ended December 31, 2014, 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, 2014 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 42) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2014, 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 80) 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, 2014, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

NON-GAAP FINANCIAL MEASURES

Algonquin uses the terms “adjusted net earnings”, “adjusted earnings before interest, taxes, depreciation and amortization” (“Adjusted EBITDA”), “adjusted funds from operations”, “per share adjusted net earnings”, “per share cash provided by adjusted funds from operations”, “per share cash provided by operating activities”, "net energy sales", and "net utility sales", throughout the Management’s Discussion and Analysis for the fiscal year ended December 31, 2013 filed as Exhibit 99.3 to this annual report on Form 40-F. The terms “adjusted net earnings”, “per share cash provided by operating activities”, “adjusted funds from operations”, “per share adjusted net earnings”, “per share cash provided by adjusted funds from operations”, Adjusted EBITDA, "net energy sales" and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of “adjusted net earnings”, Adjusted EBITDA, “adjusted funds from operations”, “per share adjusted net earnings”, “per share cash provided by adjusted funds from operations”, “per share cash provided by operating activities”, "net energy sales", and "net utility sales". Consequently, Algonquin’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “adjusted net earnings”, Adjusted EBITDA, “adjusted funds from operations”, “per share adjusted net earnings”, “per share cash provided by adjusted funds from operations”, “per share cash provided by operating activities”, "net energy sales" and "net utility sales" can be found throughout the Management’s Discussion and Analysis.

Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against Algonquin.

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, 2013, 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, 2013, 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, 2014 is filed as Exhibit 101 to this annual report on Form 40-F.

UNDERTAKING

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

CONSENT TO SERVICE OF PROCESS

Algonquin previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X.

Any change to the name or address of the agent for service of Algonquin shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin.

SIGNATURES

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

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 30, 2015

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

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the year ended December 31, 2014
99.2	Audited Annual Financial Statements for the year ended December 31, 2014
99.3	Management's Discussion & Analysis for the year ended December 31, 2014
99.4	Consent Letter from Ernst & Young LLP, Chartered Accountants
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
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101	Interactive Data File



ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 30, 2015

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*All information contained in this Annual Information Form ("**AIF**") is presented as at March 30, 2015, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.*

Caution concerning forward-looking statements

Certain statements included in this AIF contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. Forward-looking information is included throughout this Annual Information Form, 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 relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed 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. Material risk factors include those set out in this AIF under “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 information. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

Non-GAAP Financial Measures

The terms “adjusted net earnings”, “adjusted earnings before interest, taxes, depreciation and amortization” (“ **Adjusted EBITDA**”), “adjusted funds from operations”, “per share cash provided by adjusted funds from operations”, “per share cash provided by operating activities”, "net energy sales", and "net utility sales", are used throughout this AIF. The terms “adjusted net earnings”, “per share cash provided by operating activities”, “adjusted funds from operations”, “per share cash provided by adjusted funds from operations”, Adjusted EBITDA, "net energy sales" and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of “adjusted net earnings”, Adjusted EBITDA, “adjusted funds from operations”, “per share cash provided by adjusted funds from operations”, “per share cash provided by operating activities”, "net energy sales", and "net utility sales" consequently APUC’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “adjusted net earnings”, Adjusted EBITDA, “adjusted funds from operations”, “per share cash provided by adjusted funds from operations”, “per share cash provided by operating activities”, "net energy sales" and "net utility sales" can be found throughout this AIF. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC. A calculation and analysis of EBITDA and “adjusted funds from operations”, "adjusted net earnings", "net energy sales", and "net utility sales" can be found in APUC's most recent Management's Discussion & Analysis for the year ended December 31, 2014, which calculation and analysis is incorporated herein by reference.

Use of Non-GAAP Financial Measures

EBITDA

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

Adjusted funds from operations

Adjusted funds from operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company’s operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses cash provided or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements.

APUC uses adjusted funds from operations to assess its performance without the effects of (as applicable) changes in working capital balances, acquisition expenses, litigation expenses, cash provided or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP.

Adjusted net earnings

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

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

Net utility sales

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

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. 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. (the "**Unit Exchange**") and changed its name to Algonquin Power & Utilities Corp. 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 "**Company**" 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 "**Company**" 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.

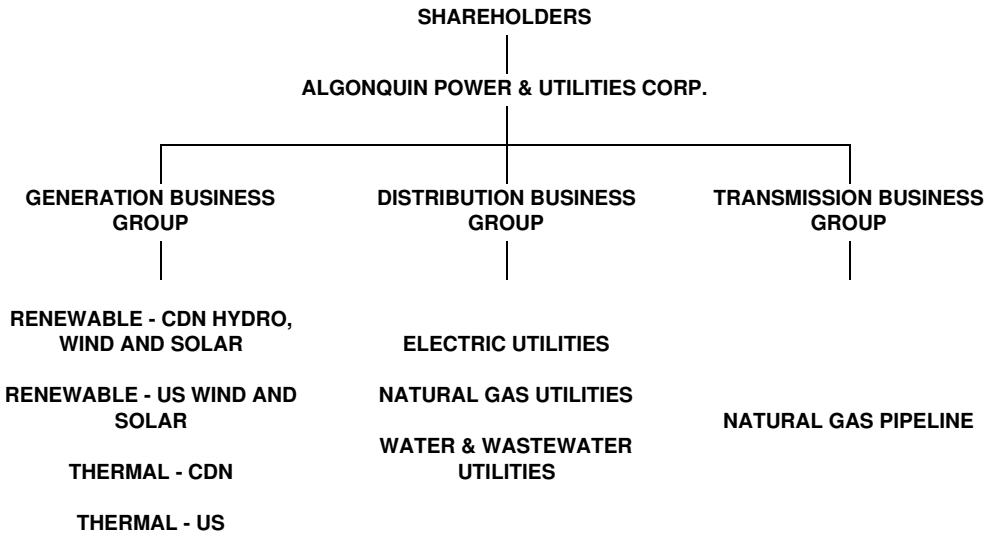
1.2 Intercorporate Relationships

1.2.1 Subsidiaries

The subsidiaries of APUC are grouped by the primary business operations of the company consisting of: the Generation Business Group ("**Generation Group**"), the Distribution Business Group ("**Distribution Group**") and the Transmission Business Group ("**Transmission Group**"). The principal holding for APUC's Generation Group is an investment in 100% of the issued and outstanding Trust Units of Algonquin Power Co. ("APCo"). The principal holding for both APUC's Distribution Group and its Transmission Group is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp. ("**LU Canada**"), a 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 issued and outstanding shares of Liberty Utilities Co. ("**Liberty Utilities**"), a Delaware corporation, which owns the utility subsidiaries as well as the sole transmission subsidiary. The Transmission Group's assets are held by Liberty Utilities (Pipeline & Transmission) Corp., a Delaware corporation which is 100% owned by Liberty Utilities Co. The ownership chains for each of the three primary business operations of the company are described below.

In regard to the Generation Group, the subsidiaries of APCo include the ownership chains of Algonquin Power Trust ("**APT**") and Algonquin Power (Canada) Holdings Inc. ("**APCH**"), as well as 100% ownership in Windlectric Inc., a federal Canadian corporation that is developing various wind projects including one in Saskatchewan and one in Ontario. 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 Distribution Group, Liberty Utilities has direct investments in electric distribution, natural gas distribution, and water distribution utility systems in California, Iowa, Illinois, Missouri, Arkansas, Georgia, Massachusetts and New Hampshire. Also, Liberty Utilities Co, through its subsidiary, Liberty Utilities (Sub) Corp., has investments in water distribution and wastewater collection utility systems in Arizona, Arkansas, Illinois, Missouri, and Texas. In regard to the Transmission Group, Liberty Utilities (Pipeline & Transmission) Corp. has a direct ownership in the Kinder Morgan Pipeline project.

The following chart summarizes the major lines of business.



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) Generation Business Group

Generation Business Group Chain Entities

APCo is the sole beneficiary of APT. 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 St. Leon Wind Energy LP. . Also, APCo owns 100.0% of the issued and outstanding shares of Cornwall Solar Inc., which owns a solar power development project in Cornwall, Ontario.

APT Group

APT forms part of the APCo business unit. 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. This trust owns all of the outstanding common shares of Algonquin Power Energy From Waste Inc. (“**APEFW**”), an Ontario corporation whose assets and operations were sold to a third party effective April 4, 2014. APT directly owns a 2% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership, a Québec limited partnership, which owns the Mont-Laurier Hydro Facility and the Côte Ste.-Catherine Hydro Facility, while APEFW owns the remaining 98% partnership interests, comprised of a 86.5% limited partnership interest and an 11.5% general partnership interest. APEFW has issued two classes of preferred shares: Class A preferred shares which are 100% owned by APCH, and Class B preferred shares which are 100% owned by APT.

APT directly owns the Hydraska Hydro Facility and 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-Eo Partnership**") which owns the Val-Eo Wind Project. A non-Algonquin entity, Val-Eo Coop de solidarité, owns 74.995% of the Val-Eo Partnership. The remaining 0.01% interest in the Val-Eo Partnership is owned by a Quebec numbered company, 9231-5498 Quebec Inc., the general partner. The interests in 9231-5498 Quebec Inc. are owned 75% by Val-Eo 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 Project. The remaining 50% is owned by Corporation Municipal de St. Damase, a non-Algonquin entity, which also owns 100% of the preferred shares issued by Saint-Damase GP.

APOT Group

APOT is an unincorporated open ended trust created by an amended and restated trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta.

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the " **St. Leon Wind Facility** "). The APOT entity that owns the St. Leon Wind Facility is St. Leon Wind Energy LP, an Ontario partnership (" **St. Leon LP** "). St. Leon LP is owned by its general partner, St. Leon Wind Energy GP Inc. (" **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. St. Leon Trust is 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, AirSource Power Fund GP Inc, a Canadian corporation which holds the remaining 0.01% general partnership interest. AirSource is also the 100% owner of St. Leon GP. 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 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 (" **Valley Power Thermal 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 Burgess and Hurdman Hydro Facilities. In Québec, APFC directly owns the facilities known as the Rawdon, Hydro Snemo, St. Raphael, Belleterre, and St. Brigette Hydro Facilities, in addition to owning 100% of the beneficial interest in the St. Alban Hydro Facility. APCH also holds a direct interest in Société Hydro-Donnacona (the "**S.E.N.C.**"), the owner of the Donnacona Hydro Facility. S.E.N.C. 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 APFC. APCH also owns 100% of Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

APCH also owns a 99% interest in Algonquin Power (Morse) LP, an Ontario limited partnership, which owns the Morse Wind Project in Saskatchewan. 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, and Algonquin Power (Marsh Hill Solar) Inc., an Ontario 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 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 project. APCI also 100% owns Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation which is the general partner, holding the remaining 0.1% general partnership interest, in the LS Partnership.

APCI also owns a 99.99% interest in Société en Commandité Chute Ford, a Quebec limited partnership which owns the Glenford hydroelectric facility. APCI also 100% owns Glenford Minority Inc., an Ontario Corporation, which is the general partner, holding a 0.01% interest in Société en Commandité Chute Ford.

APFA Group

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

APFA owns Algonquin Power Sanger LLC, a California limited liability company, and Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. These entities respectively own the U.S. Sanger and Windsor Locks Thermal Facilities. Sanger LLC directly owns 100% of Dyna Fibers Inc., a California corporation that operates a hydro-mulch business at the Sanger facility site. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA owns Algonquin Tinker Gen Co. and Algonquin 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 38.9MW of electrical generating assets in New Brunswick, and Northern Maine Gen Co. is the owner of the Millinocket and Caribou storage dams and the and Squa Pan diesel facility. APFA also 100% owns Algonquin Energy Services Inc., a Delaware corporation that is also registered in Connecticut, District of Columbia, Maine, Maryland, New Brunswick and Ohio. AES contractually provides the electrical energy requirements for commercial and industrial customers in northern Maine.

APFA 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., a Delaware corporation which is 100% owner by APFA. WP SponsorCo owns 100% of the Class B managing interests in Wind Portfolio Holdings, LLC ("**WP HoldCo**"), a Delaware LLC. Non-APUC 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 ("**U.S. Wind Portfolio Facilities**"): Sandy Ridge Wind, LLC, a Delaware LLC, owns the Sandy Ridge Wind Facility in Pennsylvania; Minonk Wind, LLC, a Delaware LLC, owns the Minonk Wind Facility in Illinois; and Senate Wind, LLC, a Delaware LLC, owns 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 in Illinois.

APFA owns Algonquin Power (Odell Holdings) Inc., a Delaware corporation, which owns 50% of Odell SponsorCo, LLC, (" **Odell SponsorCo**") a Delaware LLC. The remaining 50% of Odell SponsorCo is owned by Enel Kansas, LLC, a non-Algonquin entity. Odell SponsorCo owns Odell Holdings, LLC, a Delaware LLC, which owns Odell Holdings, LLC, a Delaware LLC, which owns Odell Windfarm, LLC, a Minnesota LLC, which owns the Odell Wind Project in Minnesota.

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 currently under construction in California. The Class A non-managing interests in SKIC 20 are owned by Firstar Development, LLC, a non-Algonquin entity. APFA also 100% owns Algonquin Power (Bakersfield Land Holdings) LLC, a Delaware LLC which holds the real property associated with the SKIC 20 project. AP Bakersfield owns 100% of Algonquin SKIC 10 Solar, LLC, a Delaware LLC which has entered into an agreement to construct a 10 MW solar project adjacent to the SKIC 20 project.

APFA also owns 100% of Algonquin Power Services America LLC, a Delaware corporation that provides purchasing services to APCo entities operating in the U.S. APFA also owns two special purpose financing companies: Algonquin Power (Finance 1) Inc. and Algonquin Power (Finance 2) Inc., both of which are Delaware corporations.

(ii) Distribution Business Group

Distribution Business 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**").

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 Utilities (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**"), which were acquired on April 1, 2013.

Liberty Utilities owns Liberty Utilities (New England Natural Gas Company) Corp., a Delaware corporation registered to do business in Massachusetts, which owns the natural gas distribution utility assets (the "**New England Gas System**") acquired on December 20, 2013 from Southern Union Company.

Liberty Utilities also owns Liberty Utilities Energy Solutions Corp., a Kansas corporation, which in turn owns Liberty Energy Solutions., a Massachusetts corporation which holds a retail gas appliance business also acquired from Southern Union Company on December 20, 2013.

Liberty Utilities owns Liberty Utilities (Pine Bluff Water) Inc., which owns and operates the Pine Bluff Water System (the " **Pine Bluff Water System**"), located in Pine Bluff, Arkansas. These assets were acquired on February 1, 2013.

Liberty Utilities owns Liberty Utilities (White Hall Water) Corp., which owns the White Hall Water System and Liberty Utilities (White Hall Sewer) Corp., owns the White Hall Waste System. These assets were acquired on May 30, 2014.

Liberty Utilities (Sub) Corp.

Liberty Utilities owns Liberty Utilities (Sub) Corp. (" **Liberty SubCo**"), which is a Delaware company. With the exception of the Pine Bluff Water System and the White Hall Water and Waste Systems, 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, Arkansas and Illinois. Most of these 100% wholly-owned subsidiaries (except Liberty Utilities (Northwest Sewer) Corp. (the "**Northwest Sewer**"), 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; 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 (Northern Sunrise Water) Corp. owns the Northern Sunrise Water System; Liberty Utilities (Rio Rico Water & Sewer) Corp. owns the Rio Rico Water & Waste Systems; Liberty Utilities (Entrada Del Oro Sewer) Corp. owns the Entrada Del Oro Waste System; and Liberty Utilities (Southern Sunrise Water) Corp. owns the Southern Sunrise Water 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.

(iii) Transmission Business Group

In respect of the Transmission Group, Liberty Utilities (Pipeline & Transmission) Corp. owns 2.5% of Northeast Expansion LLC, a Delaware LLC. Kinder Morgan Operating Limited Partnership "A", a non-Algonquin partner, owns the remaining 97.5%.

(iv) Other

Outside of APCo, LU Canada and their respective subsidiary entities, as described above, APUC directly owns, 100% of 3793257 Canada Inc. ("**3793257**"), a holding company incorporated under the CBCA.

APUC also has ownership interests in a group of special purpose financing companies, 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 in 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 owns one special purpose financing company, Liberty Utilities (U.S. Pref) Holdco Corp., an Ontario corporation. In 2014, LU Canada created a limited partnership for purposes of holding a corporate 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 notes receivable and equity 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. APT also owns a 12.1% interest in Tranche A term loan issued by Chapais Energie, Société en Commandite ("**Chapais**") which owns a wood waste facility in Chapais, Québec. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais. The term loan bear an interest rate of 10.789%.

In addition, APCo is entitled to a royalty in the form of cash flows generated by the Long Sault Hydro Facility (the " **LSR Royalty Interest**"). It is also the owner of a 14.14% secured, subordinated note (the "**LSR Subordinate 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.

As of January 1, 2013, APUC owns the Class B limited partnership units of St. Leon Wind Energy 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 a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

APUC's current quarterly dividend to shareholders is U.S. $0.0875 per share or U.S. $0.35 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "**Board**") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

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

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

The Generation Group owns or has interests in hydroelectric, wind, and solar facilities with a combined generating capacity of approximately 120 MW, 675 MW, and 10MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group owns or has interests in thermal energy facilities with approximately 335 MW of installed generating capacity. Approximately 91% of the electrical output from the owned thermal facilities is sold pursuant to long term Power purchase agreements ("**PPA**") with major utilities and which have a weighted average remaining contract life of 7 years.

The Generation Group also has a portfolio of development projects that between 2015 and 2018 will add approximately 529 MW of generation capacity from wind and solar powered generating stations with an average contract life of 22 years.

Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Distribution Business Group: The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 488,000 connections. The Distribution Group provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

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

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

The Distribution Group's regulated water distribution and wastewater collection natural gas distribution utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together server approximately 103,000 connections.

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

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 2012

Corporate

(i) Dividend increased to $0.31 per Common Share annually

APUC completed several acquisitions and advanced a number of other initiatives that raised the growth profile for APUC's earnings and cash flows which in turn supported an increase in the dividend to shareholders. As a result, on August 9, 2012, the Board approved a dividend increase of $0.03 per share annually bringing the total annual dividend to $0.31, paid quarterly at the rate of $0.0775 per Common Share.

(ii) Issuance of $120M of Preferred Shares

On November 9, 2012, APUC issued 4.8 million cumulative rate reset preferred shares, Series A (the " **Series A Shares**") at a price of $25 per share, for aggregate gross proceeds of $120 million. The shares yield 4.5% annually for the initial six-year period ending on December 31, 2018 The proceeds of the offering were used primarily to partially fund the acquisition of the interest in the U.S. Wind Portfolio on December 10, 2012.

(iii) Private Placements to Emera

During fiscal 2012, APUC issued a total of 26,380,750 Common Shares for cash proceeds of $142.6 million pursuant to the conversion of subscription receipts issued to Emera Inc. ("**Emera**") in connection with certain previously announced and completed transactions. The shares were issued in the context of the existing strategic investment agreement (the "Strategic Investment Agreement") between APUC and Emera entered into on April 29, 2011, which contemplates Emera's investment in APUC of up to 25%.

(iv) Conversion of Series 2A Convertible Debentures to Equity

On February 24, 2012 ("**Series 2A Redemption Date**"), APUC redeemed $57.0 million, being all of the remaining issued and outstanding principal amount of 6.35% convertible unsecured subordinated debentures due November 30, 2016 (the "**Series 2A Debentures**") by issuing and delivering 9,836,520 Common Shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted by the holders of such debentures into 485,998 Common Shares.

(v) Conversion and Redemption of Series 3 Convertible Debentures to Equity

On December 31, 2012, holders of $55.3 million of principal amount of 7.0% convertible unsecured debentures due June 30, 2017 (the " **Series 3 Debentures**") converted their debentures into 13,172,619 Common Shares. On January 1, 2013 (the " **Series 3 Redemption Date**"), APUC completed a redemption of the outstanding Series 3 Debentures by issuing and delivering 150,816 Common Shares for the remaining $0.96 million of principal amount of Series 3 Debentures outstanding.

(vi) Corporate Credit Facility

On November 19, 2012, APUC entered into an agreement for a $30.0 million senior unsecured revolving credit facility (the " **Corporate Credit Facility**") with a Canadian chartered bank. The credit facility is used for general corporate purposes and has a maturity date of November 19, 2015.

Generation Group

(i) Acquisition of a U.S. Wind Power Portfolio

In 2012, the Generation Group completed its 60% equity investment in the "U.S. Wind Portfolio" Facilities for consideration of $271.4 million. The portfolio consists of three facilities: the Minonk Wind Facility (200MW), the Senate Wind Facility (150MW) and the Sandy Ridge Wind Facility (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively

The U.S. Wind Portfolio Facilities were acquired through a newly formed partnership whose members include Class B members consisting of APCo (60% interest in Class B membership units) and Gamesa USA, a subsidiary of Gamesa Corporación Tecnológica, S.A., the original developer of the projects, (holding a 40% interest in Class B membership units), and certain

Class A equity investors who are primarily entitled to the tax attributes associated with the wind facilities. Total cost of APCo's interest in the U.S. Wind Portfolio was approximately $746.3 million.

The U.S. Wind Portfolio Facilities utilize Gamesa G9X-2.0 MW wind turbines. Gamesa USA has assumed all operations, maintenance, and capital repair responsibilities for the facilities pursuant to 20 year agreements for the turbines and balance of plant facilities.

The U.S. Wind Portfolio Facilities have long term energy production hedges with a weighted average life of 11.8 years (Minonk and Sandy Ridge Wind Facilities 10 years each, Senate Wind Facility 15 years). Approximately 73% of energy revenues are earned under the energy production hedges. All energy produced in excess of that included under the energy production hedges, together with ancillary services including capacity and RECs, are sold into the energy markets in which the facilities are located.

(ii) $150 million Senior Unsecured Debentures

On December 3, 2012, the Generation Group issued $150 million 4.82% senior unsecured debentures with a maturity date of February 15, 2021 (the "**2012 Generation Group Debentures**") pursuant to a private placement in Canada and the United States. The debentures were sold at a price of $99.94 per $100.00 principal amount, resulting in an effective yield to maturity of 4.83% per annum. Concurrent with the offering, the Generation Group entered into a fixed cross currency swap, coterminous with the 2012 Generation Group Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of 4.4%.Net proceeds from the 2012 Generation Group Debentures were used primarily to fund the investment in the U.S. Wind Portfolio.

(iii) Generation Credit Facility

On November 16, 2012, the Generation Group amended its revolving credit facility (the "**Generation Credit Facility**") to increase the commitments available under the facility to $200 million and extended the maturity date to November 16, 2015. In addition, the bank syndicate agreed to release its security previously held over certain APCo entities, such that the amended Generation Credit Facility became fully unsecured.

(iv) Completion of Windsor Locks Thermal Facility Repowering

The Generation Group completed the repowering of the Windsor Locks Thermal Facility's electrical and steam energy generating facility in 2012 with the installation of a new 14 MW Solar Titan combustion gas turbine in July 2012 at a total capital cost of U.S. $18.3 million (net of one-time non-recurring items: State of Connecticut grant for U.S. $6.5 million; and a U.S. federal government heat and power investment tax credit for U.S. $2.4 million). As part of the repowering project, the Generation Group had previously entered into an extension of the energy services agreement with Ahlstrom for delivery of 100% of its steam capacity and a portion of its electrical generating capacity. The agreement now continues until 2027. With the new turbine operational, the existing Frame 6 is available as a peaking turbine to generate additional revenues.

Distribution Group

(i) Acquisition of Remaining Interest in CalPeco Electric System

On December 21, 2012, the Distribution Group completed the acquisition of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which indirectly owned 100% of the CalPeco Electric System assets. The Distribution Group acquired the remaining 49.999% interest from Emera through proceeds received from the issuance of 8,211,000 Common Shares of APUC on the conversion of subscription receipts previously issued to Emera. 4,790,000 of such shares which were issued on December 27, 2012, and the remaining 3,421,000 shares were issued on February 14, 2013.

(ii) Acquisition of New Hampshire Utilities

On July 3, 2012, the Distribution Group completed the acquisition of all issued and outstanding shares of the entities owning the Granite State Electric System and the EnergyNorth Gas System, both from National Grid, for consideration of U.S. $285.0 million plus working capital and other closing adjustments for total consideration of U.S. $286.7 million. The regulated electric distribution company provides electric service to over 43,800 connections in 21 communities in New Hampshire and the regulated natural gas distribution utility provides natural gas service to over 91,100 connections in five counties and 30 communities in New Hampshire. For more information concerning this acquisition, refer to the amended and restated business acquisition report dated October 26, 2012 and filed on APUC's SEDAR profile.

(iii) Acquisition of Midstates Gas System

On August 1, 2012, the Distribution Group completed the acquisition of regulated natural gas distribution utility systems located in Missouri, Illinois, and Iowa from ATMOS Energy Corporation ("Atmos") for consideration of U.S. $127.7 million

plus working capital and other closing adjustments for a total consideration of U.S. $128.2 million. Collectively, the regulated natural gas distribution systems provide natural gas service to approximately 85,600 connections.

(iv) U.S. Debt Private Placements

In connection with the above noted gas and electric utility acquisitions during the third quarter of 2012, the Distribution Group completed a U.S. $225 million private placement debt financing. The financing was closed in two tranches contemporaneously with, and was issued to partially fund, the acquisitions of the Granite State Electric System, the EnergyNorth Gas Systems, and the Midstates Gas System. The notes are senior unsecured notes with an average life maturity of over ten years and a weighted average coupon of 4.38%. The notes have been assigned a rating of “BBB high” by DBRS.

(v) Expansion of Distribution Credit Facility

In 2012, the Distribution Group entered into an agreement for a U.S. $100 million three year senior unsecured revolving credit facility (“**Distribution Credit Facility**”) with a consortium of U.S. banks.

(vi) Successful Completion of the CalPeco Electric System Rate Case

On February 17, 2012, the Distribution Group filed a general rate case and on November 29, 2012, approval of the All Parties General Rate Case Settlement was received from the CPUC. As an element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account was agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility. Primarily as a result of the rate case at the CalPeco Electric Utility, additional EBITDA of $7.1 million is expected in 2013.

2.2.2 Fiscal 2013

Corporate

(i) Dividend Increased to $0.34 per Common Share Annually

Resulting from a higher growth profile and consistent with APUC's stated strategy of delivering total shareholder return comprised of an attractive current dividend yield and capital appreciation, on May 9, 2013, the Board approved a dividend increase of $0.0375 per share annually bringing the total annual dividend to $0.34, paid quarterly at the rate of $0.085 per Common Share.

(ii) Credit Rating Upgrade

In the fourth quarter of 2013, S&P raised its long-term corporate credit rating on APUC, APCo and Liberty Utilities to 'BBB' from 'BBB-'. As well, S&P raised its global scale and Canada scale preferred stock ratings on APUC to 'BB+' and 'P-3 (High)' from 'BB' and 'P-3', respectively. S&P provided a stable outlook for APUC owing to the assessment of relatively stable cash flows, supported by regulated cash flow from Liberty Utilities' regulated utility business, and APCo's largely contracted power asset portfolio.

(iii) Related Party Transactions

In 2011, the Board formed an independent committee (“**Independent Board Committee**”) and initiated a process to review all of the remaining historic business associations with APUC's Chief Executive Officer (“**CEO**”) and Vice-Chair with an objective to reduce and/or eliminate these relationships. The process was largely completed during the 2013 fiscal year and the processes to resolve related party transactions between APUC and the CEO and Vice Chair have been identified to the satisfaction of the Independent Board Committee and the Board. See "*Description of Business - Business Associations with APMI and Senior Executives*".

(iv) Emera Subscription Receipts

Pursuant to previously committed subscription receipts, on February 7, 2013, APUC issued 2,614,005 Common Shares at a price of $5.74 per share to Emera. Additionally, on February 14, 2013, APUC issued 5,228,011 Common Shares at a price of $5.74 per share and 3.4 million Common Shares at a price of $4.72 per share to Emera. On March 26, 2013, APUC issued 4.0 million Common Shares at a price of $7.40 per share for total cash proceeds of $29.3 million pursuant to a subscription agreement with Emera.

APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

(v) Conversion and Redemption of Series 3 Convertible Debentures to Equity

On January 2, 2013, APUC completed a redemption of the outstanding Series 3 Debentures by issuing and delivering 150,816 Common Shares for the remaining $1.0 million principal amount of Series 3 Debentures outstanding.

(vi) Expansion of the Corporate Credit Facility

On November 19, 2013, APUC amended its Corporate Credit Facility to increase the commitments available to $65.0 million and extend the maturity date to November 19, 2016.

Generation Group

(i) Acquisition of the 20 MWac Bakersfield Solar Project

On November 28, 2013, the Generation Group entered into an agreement to purchase and complete construction of a 20 MWac solar facility (the "**Bakersfield Solar Project**") located in Kern County, California. Following commissioning, the Bakersfield Solar Project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement. The Generation Group entered into a partnership agreement with a third party (the "**Tax Partner**") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. The Tax Partner will contribute U.S. $22.8 million to the project with the remaining of the total estimated cost of U.S. $58.5 million to be funded by the Generation Group.

(ii) Acquisition of Shady Oaks Wind Facility

On January 1, 2013, APCo acquired a 109.5 MW contracted wind generating facility (the "**Shady Oaks Wind Facility**") from Goldwind International SO Limited ("**Goldwind**") by assuming long-term debt of U.S. $150 million for no additional cash, subject to final closing adjustments for working capital, energy generated by the project and basis differences between node and hub prices.

The Shady Oaks Wind Facility is located in Northern Illinois, approximately 80 km west of Chicago, Illinois and achieved commercial operation in June 2012.

The facility is comprised of 68 Goldwind GW82 1.5MW and 3 Goldwind GW100 2.5MW permanent magnet direct-drive wind turbines; these turbines are well suited for the wind regime, and offer significant technological advantages providing proven reliability, enhanced energy production efficiency and lower long term maintenance costs. An affiliate of Goldwind has assumed all operations, maintenance, and capital repair responsibilities for the Shady Oaks Wind Facility turbines pursuant to a 20 year fixed price agreement.

The Shady Oaks Wind Facility has entered into a 20 year inflation indexed power purchase agreement with the largest electric utility in the state of Illinois, Commonwealth Edison (BBB flat stable: Moody's, S&P) for 310 GW-hrs of energy per year. All energy produced in excess of that sold under the power purchase agreement is sold into the energy market in which the facility is located.

(iii) Energy From Waste Facility

During the second quarter of 2013, the Generation Group concluded that its EFW Thermal Facility and BCI Thermal Facility were no longer considered strategic to its ongoing operations, commenced a process to divest of the facilities and wrote the net assets of the facilities down to their estimated fair value, less cost of sale which resulted in a write down of $35.7 million, net of tax. On February 7, 2014, an agreement to sell the EFW and BCI Thermal Facilities was reached. Accordingly, the determination of the fair values of the net assets of EFW and BCI Thermal Facilities were revised to reflect the estimated selling price under the agreement, which resulted in a further write down of the net assets of $6.8 million net of tax as at December 31, 2013. The transaction closed on April 4, 2014.

(iv) Sale of Small U.S. Hydro Facilities

On March 14, 2013, the Generation Group entered into an agreement to sell ten small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of APUC for gross proceeds of U.S. $27.0 million. The Generation Group closed the sale of nine of the ten facilities on June 29, 2013 for total proceeds of approximately U.S. $23.4 million with the sale of the tenth facility closing on June 17, 2014.

Distribution Group

(i) Acquisition of the New England Gas System

On February 11, 2013, the Distribution Group entered into an agreement with The Laclede Group, Inc. ("**Laclede**") to assume Laclede's rights to purchase the assets of the New England Gas Company from an affiliate of Southern Union Company. The

New England Gas System is a natural gas distribution utility serving over 55,000 connections in Massachusetts. The acquisition closed in the fourth quarter of 2013.

Total purchase price for the New England Gas System, net of the debt assumed was approximately U.S. $62.7 million, including the purchase price adjustment of U.S. $3.1 finalized in the second quarter of 2014. The acquisition was funded using a targeted 52% equity, 48% debt capital structure including the assumption of U.S. $19.5 million of existing debt.

(ii) Acquisition of the Peach State Gas System

On August 8, 2012, the Distribution Group entered into an agreement with Atmos to acquire certain regulated natural gas distribution utility systems in Georgia serving approximately 60,000 connections in the State of Georgia. On April 1, 2013 the Distribution Group completed the acquisition for a total purchase price adjusted for certain working capital and other closing adjustments of approximately U.S. $153.0 million.

(iii) Acquisition of the Pine Bluff Water System

On February 1, 2013, the Distribution Group completed the acquisition of the issued and outstanding shares of United Water Arkansas Inc., a regulated water distribution utility from United Waterworks Inc. The Pine Bluff Water System is located in Pine Bluff, Arkansas and serves approximately 17,700 water distribution connections. Total purchase price for the Pine Bluff Water System, adjusted for certain working capital and other closing adjustments, was approximately U.S. $27.9 million.

(iv) U.S. Debt Private Placements

On July 31, 2013, the Distribution Group issued U.S. $125.0 million of debt through a private placement in the U.S. The financing is the third series of notes issued pursuant to Liberty Utilities' master indenture. The notes are senior unsecured with an average life maturity of approximately ten years and a weighted average coupon of 3.81%. The proceeds of the private placement financing were used to repay a U.S. $100.0 million short term acquisition facility used in connection with the acquisition of the Peach State Gas System, reduce the drawn amount on Generation Credit Facility and for general corporate purposes.

On March 14, 2013, the Distribution Group completed a U.S. $15.0 million private placement debt financing. The notes are senior unsecured with a 10 year term and a coupon of 4.14%.

(v) Expansion of the Distribution Credit Facility

On September 30, 2013, the Distribution Group increased the credit available under its revolving credit facility (the " **Distribution Credit Facility** ") the Distribution Credit Facility to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides the Distribution Group with the additional liquidity required as a result of the various acquisitions completed in 2013 and for execution of near term organic growth opportunities. In addition to a larger credit facility, the tenor has been increased from three years to five years and several other terms under the facility, including pricing, were improved. The amended facility now expires on September 30, 2018.

(vi) Successful Completion of the Rio Rico Water System Rate Case

On May 31, 2012, the Distribution Group filed a general rate case with the Arizona Corporation Commission ("ACC") related to the Rio Rico Water System. The filing sought, among other things, an increase in EBITDA by U.S. $0.8 million over 2011 results if approved as filed. On July 17, 2013, an order was received from the ACC which corresponds to an increase in EBITDA of approximately U.S. $0.4 million per year.

(vii) Successful Completion of the EnergyNorth Gas System Rate Case

On May 15, 2013, the Distribution Group filed its required fiscal year 2013 (April 1, 2012 - March 31, 2013) cast iron/bare steel (CIBS) replacement program results for EnergyNorth Gas System with the NHPUC. As part of this filing, Liberty requested an annual increase in base distribution rates of U.S. $0.2 million effective July 1, 2013. On June 26, 2013, the NHPUC approved the increase.

(viii) Successful Completion of the Midstates Gas System Rate Case

On July 2, 2013, the Distribution Group filed an application with the Missouri Public Service Commission (" **MPSC** ") seeking accelerated recovery for infrastructure deployed under the Midstates Gas System's infrastructure system replacement surcharge ("**ISRS**"). The filing was approved by MPSC on October 16th, 2013 which is expected to increase revenues and EBITDA by U.S. $0.6 million.

2.2.3 Fiscal 2014

Corporate

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

In 2014 the company successfully advanced various initiatives raising the growth profile for earnings and cash flows which in turn supported an increase in the dividend to shareholders. As a result, 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 are approximately 80% based in the U.S. and generate 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 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 Offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the September Offering. As a result, APUC issued an aggregate of 19,389,000 common shares under the 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 entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,865,170 subscription receipts ("**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 the Over-Allotment Option, 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 are intended to be used to partially finance the acquisitions of the Odell Wind Project and the Park Water Facility.

Generation Group

(i) Acquisition of Odell Wind Project

On September 4, 2014, the Generation Group announced an opportunity to acquire an interest in the Odell Wind Project, of Minnesota. The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and 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 is expected to begin in the second quarter of 2015, with total costs estimated at U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in late 2015 or early 2016.

(ii) Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Generation Group completed the construction of its 10 MWac solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014 for a total capital cost of approximately $47.6 million. The facility represents the first solar project in the 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 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 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 Quebec.

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Project will qualify as Canadian Renewable and Conservation Expense ("**CRCE**"), and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec tax credit ("**Quebec CRCE Tax Credit** "). The estimated value of the Quebec CRCE tax credit for the Saint-Damase project is expected to be approximately $16.6 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 intends to proceed with a 10 MW project adjacent to its 20MW Bakersfield I Solar project in Kern County, California, which is currently under construction.

The 10MW Bakersfield II Solar project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20MW Bakersfield I Solar project. Construction of Bakersfield I Solar is nearing completion, with commercial operations expected to occur in the first quarter of 2015.

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

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

On March 31, 2014, the 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 U.S. Wind Portfolio in the United States for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the 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 Generation Group early in 2014 as discussed below.

(vi) $200 million Senior Unsecured Debentures

On January 17, 2014, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "2014 Generation Group Debentures") pursuant to a private placement in Canada and the United States. The 2014 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 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 Generation Group increased the credit available under the senior unsecured credit facility (the " Generation Group Credit Facility") to $350.0 million from $200.0 million. The larger credit facility provides additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018

Distribution Group

(i) Agreement to acquire Park Water System

On September 19, 2014, the Distribution 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 ("**Park Water System**"). 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 is expected to be approximately U.S. $327.0 million, which includes the assumption of approximately U.S. $77.0 million of existing long-term utility debt. The acquisition will maintain APUC's strategic business mix and further enhance its investment grade consolidated capital structure.

(ii) Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4.5 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 commission 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 GRAM filing with the GPSC. In January 2014, the Distribution 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). Commission approval was received on December 4, 2014.

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

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water 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 addition to a revenue increase, the application sought 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 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 ISRS surcharge (infrastructure system replacement surcharge). 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 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. The previous test year ended September 30, 2009. An Order and new rates are expected in the second quarter of 2015.

(viii) EnergyNorth Gas System Rate Case Proceedings

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Distribution Group ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. 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.

Transmission Group

(i) Agreement to acquire interest in Natural Gas Transmission Pipeline

On November 24, 2014, APUC announced its agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan Operating L.P. Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, and Kinder Morgan Operating L.P. "A" have agreed to form a new entity ("**Northeast Expansion LLC**") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts. The project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that the project will receive a Federal Energy Regulation Commission ("**FERC**") certificate in the fourth quarter of 2016, with commercial operations occurring by late 2018.

Under the agreement, APUC will initially subscribe for a 2.5% interest in Northeast Expansion LLC with an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. $400 million, depending on the final pipeline configuration and design capacity

2.3 Recent Developments - 2015

Corporate

(i) Issuance of Fourth Quarter and Year End Financial Results

Shortly before the originally scheduled release of its 2014 financial results, APUC became aware of certain anonymous, unproven allegations regarding certain APUC personnel. APUC shared the allegations with its auditors, and delayed releasing its financial results in order to consider, together with the auditors, whether certain of the allegations which related to Algonquin's financial reporting and related practices could impact its financial results. This assessment, which was led by a committee of independent directors with the assistance of independent legal and accounting advisors was completed and on March 16, 2015 APUC released its financial results, having determined that the allegations did not impact APUC's financial results. The committee's investigation into the allegations which are not related to APUC's financial reporting and related practices is continuing to be dealt with in a confidential manner in accordance with APUC's complaint-handling policies.

Generation Group

(i) Completion of Morse Wind Project

Construction of the Morse Wind Project near Morse, Saskatchewan is in its final stages. Installation of access roads and foundations are complete, turbine delivery commenced in January 2015, all turbines have been erected. The project is expected to be operational by March 31, 2015. Currently, four out of 10 turbines have been commissioned and are generating energy which is being sold to SaskPower at 100% of the PPA rate.

(ii) Completion of Bakersfield I Solar Project

Construction on the Bakersfield I Solar Project near Bakersfield, California began in the second quarter of 2014 and was placed in service on December 30, 2014. Final construction efforts are nearing completion and the project is currently

generating electricity which is being sold to PG&E at prevailing market rates until the project reaches COD early in the second quarter of 2015.

Distribution Group

(i) **Acquisition of New Hampshire Gas**

On January 2, 2015, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. $3.0 million, subject to certain closing adjustments.

3. DESCRIPTION OF THE BUSINESS

3.1 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 company operates has various pieces of legislation in effect which the business must comply with. 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 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 company 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 United States FERC under the U.S. Federal Power Act (“ **FPA**”), Public Utilities Regulatory Policies Act (“**PURPA**”) and the Public Utility Holding Company Act of 2005 (“ **PUHCA**”).

(1) Rate Regulation

All of APUC’s operating US 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 APUC’s operating US 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. 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) 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 Generation Group's intermediate holding companies claims exemption from PUCHA under 18 CFR Section 366.3, 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 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 ("**Power Pool**") was established under the EUA to provide a competitive, real-time spot market for electric energy. The 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 Power Pool.

The EUA has also established the Alberta Electric System Operator (" **AESO**") to operate and manage the Power Pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy in Alberta. The AESO is governed by an independent board appointed by the Alberta Minister of Energy.

The AESO spot market, or pool price, is determined by market forces. The AESO accepts offers to sell power and bids to buy power through its Energy Trading System. The AESO then dispatches electricity in accordance with an economic merit order based on the lowest cost offers to supply demand in real time. All energy traded through the Power Pool is financially settled each hour at a single spot market price.

Three categories of sellers are eligible to offer and sell electricity through the Power Pool: marketers, importers and independent power producers. There are also three categories of eligible purchasers who may bid to acquire electricity from the Power Pool: retailers, direct access customers and exporters.

(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 holds all rights, obligations and liabilities under, and purchases the energy generated by the Ontario facilities in which APUC has an interest pursuant to, 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.

With a total installed capacity of 36,643 MW (in 2014), Hydro-Québec provides a clean, renewable, and reliable supply of electricity to all Québecers. It also sells power on wholesale markets in northeastern North America. Hydro-Québec has been generating, transmitting and distributing electricity for over half a century. The company is a world leader in the field of hydroelectricity.

As a result of its vast hydropower resources, Hydro-Québec's electricity rates are among the lowest in North America.

Similar to Ontario, the Québec government develops the regulatory framework for wholesale and retail competition. Since 1991, Hydro-Québec has procured some of its power requirements from private producers on terms and rates negotiated with each producer. The province continues to introduce various programs to stimulate renewable power from hydroelectric and wind powered facilities as well as cogeneration plants fuelled by biomass and natural gas.

In April 2002, the Québec government adopted the Dam Safety Act (Quebec) pursuant to Bill C-93 (" **Bill C-93**") and corresponding regulations. Bill C-93 imposes a series of safety measures governing the construction, alteration and operation of high-capacity dams. It requires dam owners to maintain their facilities in good repair and monitor their hydraulic works. As a result of this legislation, APUC's Renewable Energy Division was required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APUC within the Province of Québec.

In the past three years, APUC has spent approximately $2.0 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APUC currently estimates further capital expenditures of approximately $7.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years estimated approximately as follows:

(all dollar amounts in $ millions)	Total	2015	2016	2017	2018
Future Estimated Bill C-93 Capital Expenditures	**7.9**	1.0	3.1	3.5	0.3

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

The Generation Group is presently working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Belleterre Hydro Facility that are not required for power generation. The Generation Group anticipates completion of any required work on these dams by 2017.

Engineering for the Rivière-du-Loup Hydro Facility was completed in 2012. Following additional geotechnical investigation in 2014, the remediation work is now estimated at $1.1 million. Completion of the remedial work is anticipated in 2015.

The dam safety study and a detailed condition assessment for the St. Alban Hydro Facility have been completed. The Generation Group anticipates engineering and regulatory review for the remediation of the main dam to be completed in 2015, with remedial work in 2016 to 2017.

On May 18, 2014, the Donnacona Hydro Facility experienced ice damage during the spring thaw and has been shut down. The Generation Group had previously planned Capital Expenditures for the Donnacona Hydro Facility in 2015 and 2016 in the amount of $7.8 million. It has been determined, in consultation with its 3rd party engineers, that a dam re-build is required to return the facility to operation. The Generation Group is currently evaluating environmental permitting and rebuild scenarios. Consequently, the Generation Group does not anticipate any near-term expenditures related to C93 compliance of the existing structure.

In addition to the C-93 related dam remediation work, the Generation Group has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

(iii) Material Facilities

(1) Long Sault Hydro Facility

The Long Sault Rapids facility (the "**Long Sault Hydro Facility**") is an 18 MW hydroelectric generating facility located on the Abitibi River, 19 kilometers north of the Town of Cochrane, in northern Ontario. The facility was commissioned on April 1, 1998.

The facility was developed by a joint venture between Algonquin Power (Long Sault) Partnership and N-R Power Partnership. The facility is owned by the co-owning joint ventures ("**Co-Owners**") as tenants-in-common and not as joint tenants, with the Co-Owners each having an undivided 50% interest in the facility. The partners in the Algonquin Power (Long Sault) Partnership are Algonquin Power (Long Sault) Corporation Inc. and Algonquin Power Corporation Inc. ("**APC**"). Algonquin Power (Long Sault) Corporation Inc. is a wholly-owned subsidiary of APC. APC is a wholly-owned subsidiary of APCH. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There is a non-recourse loan outstanding which is secured against the facility and the Co-Owners' interest therein. See "Credit Agreements" below.

APUC's interest in the facility was originally acquired by way of subscribing to two notes from the original developers. The notes receivable have a face value of approximately $17 million and bear interest at 9%. APUC earns interest income on the notes and is entitled to 100% of any incremental after tax cash flows from the facility up to 2013, 70% of any incremental after tax cash flows from 2014 to 2027 and 62.5% of any incremental after tax cash flows thereafter. APUC also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

The facility is a "run of the river" facility, which means there is a continuous discharge of water from the facility with no storage and release of water. The powerhouse is an integrated structure, housing four 4,500 kilowatt pit turbine generating units.

PPA

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the facility exclusively to OEFC. The PPA terminates 50 years from the commercial in-service date, April 1, 1998, and 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 Co-Owners receive a monthly capacity payment when the facility delivers an average of at least 1,800 kilowatts of power delivered to the delivery point in each fifteen minute interval to OEFC during at least 85% or more of the On-peak period fifteen minute intervals for that month. The "**On-peak**" period is between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays, and " **Off-peak**" is the other remaining hours. Monthly energy in excess of 115% of target generation is subject to an additional payment.

Waterpower Lease

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. The annual water rental charge commenced in January 2008.

Co-Owners Agreement and Management Agreement

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.

Credit Agreement

There is an outstanding senior loan against the facility in the amount of $36.0 million as at December 31, 2014. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("**Clarica**"), The Canada Life Assurance Company and the Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years, maturing in January 2028 and bears interest at an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse to APUC and is secured by the facility and the ownership interests therein.

Under the terms of the credit agreement, a debt reserve is required. In 2008, APUC issued an irrevocable letter of credit in an amount of $1.2 million to replace the debt service escrow deposit.

Residual Ownership Interest

APUC's interest in the Long Sault Hydro Facility is by way of subscribing to two notes from the original developers, which effectively entitles APUC to 100% of after tax cash flows of the facility up to 2013, 70% from 2014 to 2027 and 62.5% thereafter. APUC also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

An affiliate of Algonquin Power Management Inc. was one of the original partners in the facility and was entitled to receive 5% of the equity cash flows commencing in 2014. On December 31, 2013, APUC acquired such residual partnership interest in the Long Sault Rapids Hydro Facility as part of an agreement to resolve a number of the historic business relationships between APUC and APMI. See “Description of the Business – Business Associations with APMI and Senior Executives - Equity interests in Rattle Brook Hydro, Long Sault Hydro, and BCI Thermal Facilities”.

(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 from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec. In 2009, the water rights lease was renewed for a term of 21 years commencing March 1, 2009. 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 “*Risk Factors - Operational Risks Management - Litigation Risks and Other Contingencies*”.

(3) Mont Laurier Hydro Facility

The Mont Laurier Hydro Facility is a 2.7 MW hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The Mont Laurier Hydro Facility is owned by the Mont-Laurier Partnership.

The facility is constructed on lands owned by the Mont-Laurier Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources (Québec) pursuant to a lease agreement dated March 23, 1988 and assigned to the Mont Laurier Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.

(4) Côte Ste-Catherine and Mont Laurier PPAs - General

Each of the Côte Ste-Catherine and Mont Laurier Hydro Facilities 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.

Power purchase rates under the Hydro-Québec agreements (other than for the Mont Laurier and Côte Ste-Catherine Hydro Facilities) increase in accordance with the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. The Mont Laurier Hydro Facility is subject to a fixed annual escalation of 1.8%. The Côte Ste-Catherine Hydro Facility (Phase I) power purchase rate increases at a fixed annual index of 1.1% for the first four years and 1.8% thereafter.

(5) Tinker Hydro Facility

The 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 38.9 MW. Historical gross generation from the station averages 140,000 MW-hrs per year. The Tinker Hydro Facility benefits from the flow regulation of the Millinocket Dam and Squa Pan hydro facilities, both of which are also owned and operated by APCo.

As part of the generation assets in New Brunswick and Northern Maine, APUC owns an electrical transmission system consisting of 14.7 km 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.

The Tinker Hydro Facility supplies approximately 31,000 MW-hrs per year to the municipal utility of Perth-Andover under a PPA expiring in 2021. The remaining generation from the plant, approximately 109,000 MW-hrs per year, is sold to retail commercial and industrial customers in the Maine and New Brunswick markets, as well as energy and capacity to the Maine and New Brunswick electricity markets.

Energy Marketing

The primary business of the Energy Marketing Group is to market the output of the Tinker Hydro Facility and other owned assets of APUC which sell the energy they generate and any applicable environmental attributes less any associated transportation costs. Additionally, the group manages gas purchases for the Windsor Locks Thermal Facility, and supports the development of strategies for selling the power output of other facilities of APUC that are approaching the end of their PPA lives. The Energy Marketing Group provides energy to commercial and industrial customers in the Northern Maine and Southern Maine markets primarily by purchasing energy from the Tinker Hydro Facility. Based on historical long term average levels of hydroelectric energy generation, the Tinker Hydro Facility provides approximately 65% of the energy required to service the Northern Maine customers and provides a natural hedge on supply.

The Energy Marketing Group purchases additional energy and applicable environmental attributes from the market to supplement the purchases from the Tinker Hydro Facility in order to service its customer demand, and sells any excess generation to the market. Risk associated with this business is managed through the purchase of fixed volume/prices from the market. In addition, the Energy Marketing Group 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.

The Energy Marketing Group is responsible for purchasing gas for the Windsor Locks Thermal Facility located in Connecticut.

(6) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 kilometers west of the Town of Innisfail, Alberta. The 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 facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

APUC sells all of the power generated at the Dickson Dam Hydro Facility in the Alberta Power Pool. In addition, APUC has entered into a fixed financial hedge agreement with CP Energy Marketing L.P. running from May 15, 2012 through December 31, 2016 for variable monthly volumes. The Dickson Dam Hydro Facility hedge covers approximately 75% of the expected annual generation volume from the facility.

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 favor 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 Wind Facility, and Quebec for the St. Damase Wind Facility. 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 Wind Facility, and Hydro Quebec Distribution ("**Hydro Quebec**") in the case of the St. Damase Wind Facility. 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 ("**PJM**") and Electric Reliability Council of Texas regional markets (" **ERCOT**").

(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 anticipates requiring 1,700 MW of additional supply by 2020 and 3,700 MW by 2030 to accommodate load growth and the retirement of generation facilities. 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 99% of electricity mix, and as such, the utility has encouraged the development of wind projects in the province in recent years. Hydro-Québec held wind project calls for tenders in 2005 and 2009 that directly resulted in 2,187 MW of wind capacity to be installed in the province. Additional 450 MW calls for tenders were issued in 2013, seeking energy to be delivered in 2016 or 2017, and in March 2015, seeking 500 MW to be delivered in 2018 or 2019.

(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) Minnesota

The Midcontinent Independent System Operator ("**MISO**") is an Independent System Operator ("**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 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 facility is owned by St. Leon LP.

On September 18, 2007, the St. Leon Wind Facility achieved commercial operation pursuant to a turn-key construction contract dated November 12, 2004. In January 2010, APUC executed an Operation and Maintenance Service Agreement with Vestas-Canadian Wind Technology, Inc. ("**Vestas**") whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon Wind Facility for approximately 20 years.

St. Leon LP and St. Leon GP have entered into a PPA with Manitoba Hydro dated as of October 28, 2004 under which all electricity produced at the St. Leon Wind Facility is sold to Manitoba Hydro. As of June 17, 2006, the facility achieved commercial operation status under the PPA with Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional 5 years. Under the terms of the PPA, security in an amount of $1.8 million is required. The security was fully funded using an irrevocable letter of credit.

St. Leon LP entered into a Wind Power Production Incentive (" **WPPI**") agreement with the Ministry of Natural Resources - Canada which entitles the St. Leon Wind Facility to receive an incentive from the federal government of $10.00 per MW-hr to a maximum of $3.7 million annually for a period of ten years ending March 2016.

(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.

In July 2011, an affiliate of APUC executed a 25-year PPA with Manitoba Hydro in respect of the St. Leon II Wind Facility. As of July 1, 2012, the facility started generating revenues in accordance with its PPA. Under the terms of the PPA, operational security in the amount of approximately $0.3 million is required until 60 days after the expiry of the term or renewal term, as the case may be. The security was fully funded using an irrevocable letter of credit.

In July 2011, an affiliate of the company executed an operation and maintenance service agreement with Vestas whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon II for approximately 20 years.

(3) Red Lily Wind Facility

The Red Lily I wind facility (the "**Red Lily Wind Facility**") is a 26.4 MW wind generating facility located 5 kilometers west of Moosomin, Saskatchewan. The Red Lily Wind Facility consists of 16 Vestas V82 wind turbine generators. The equity in the Red Lily Wind Facility is owned by an independent investor, Concord Pacific Group. The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership. As at December 31, 2014, APUC has a senior debt investment in the facility of $11.6 million that bears interest at the rate of 6.31% per annum and a subordinated debt investment in the facility of $6.6 million that bears interes at the rate of 12.5% per annum. In addition to the loans extended by APUC, an additional $31.0 million of senior debt has been provided by a third party lender. APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable in February 2016. In addition to interest payments on its debt financing, APUC is entitled to certain supervisory fees.

On July 30, 2008, the Red Lily Wind Facility entered into a PPA with SaskPower. The PPA term is 25 years from commencement of commercial operation which was February 23, 2011. The PPA also includes a 2% annual increase throughout the term of the agreement.

(4) St. Damase Wind Facility

The St. 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.

In May 2011, Société en Commandite Fleur de les Éoliennes Saint-Damase executed a 20-year PPA with Hydro Québec in respect of the St. Damase Wind Facility. Construction of the facility was completed on December 2, 2014 for a total net book value of generating assets of $69.7.

In November 2013, Société en Commandite Fleur de les Éoliennes Saint-Damase executed an Enercon Partner Konzept Agreement with Enercon whereby Enercon provides service and maintenance services at a contracted rate to the St.-Damase Wind Facility for 15 years.

Under the terms of the PPA, operational security in the amount of approximately $0.9 million is required, which has been fully funded using an irrevocable letter of credit.

The St. Damase Wind Facility currently has outstanding senior and subordinated loans. The senior loan is in the amount of $23.4 million as at December 31, 2014. The senior loan was provided by a credit facility comprising third party members as arranged by Algonquin Power Co. and carries a term of 20 years, maturing in December 2034, and bearing at an interest rate of 5.5%. The senior loan is interest only and payable semi-annually. Additionally, the project has subordinated loans totalling $35.2 million as at December 31, 2014. The subordinated loan is split into two tranches of $10.6 million and $24.6 million with the municipality of St. Damase and Algonquin Power Co. respectively. Each subordinated loan carries a term of 20 years, maturing in December 2034, and bears an interest rate of 10.0%. The loan is non-recourse to APUC and is secured by the facility and the ownership interests therein.

(5) 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 is owned by GSG 6, LLC, an entity acquired by APFA from Goldwind on January 1, 2013.

GSG 6, LLC is party to a fixed price Service and Maintenance Agreement with an affiliate of Goldwind, the original equipment manufacturer, whereby the affiliate provides turbine operation, maintenance and repair services at a contracted rate to the Shady Oaks Wind Facility for the duration of the warranty period under the project turbine supply agreement, which is approximately 20 years.

GSG 6, LLC has entered into 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. The Shady Oaks Wind Facility reached commercial operation in June 2012. Under the terms of the power sales contract, GSG 6, LLC is required to provide security in an amount of US$4.7 million. That obligation is being maintained by Goldwind utilizing an irrevocable letter of credit with an associated fee being assessed to APFA.

As at December 31, 2014, the outstanding amount of the Shady Oaks Project Wind Facility project debt facility with the China Development Bank Corporation was U.S. $76.0 million. On APUC's year-end financial statements for the twelve months ended December 31, 2014, U.S. $6.0 million of such facility is classified as current, based on payments of U.S. $3.0 million due on each of May 15, 2015, and November 15, 2015. The semi-annual principal repayment schedule under the facility for the following 11.5 years ranges from U.S. $3.0 million to U.S. $6.0 million with a final repayment of U.S. $20 million in 2026. The debt may be repaid in whole or in part on an interest payment date without penalty and bears interest at LIBOR plus 280 basis points.

(6) 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. The Sandy Ridge Wind Facility is owned by Sandy Ridge Wind, LLC. APFA indirectly owns 100% of the managing ownership interests in Sandy Ridge Wind, LLC through WP SponsorCo.

As part of APFA's acquisition of a controlling interest in Sandy Ridge Wind, LLC, Gamesa USA and Sandy Ridge Wind, LLC entered into an asset management and balance of plant operations and service agreement ("**AMBOSA**") under which Gamesa USA provides asset management and balance of plant operations to the owner for a period of 20 years, and an operations and maintenance agreement under which turbine operation, maintenance and repair services are provided at a contracted rate to the Sandy Ridge Wind Facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's turbine supply agreement.

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 an Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the energy market in which the Sandy Ridge Wind Facility is registered.

(7) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind energy facility located near Minonk, IL, 200 km southwest of Chicago, IL. The facility is owned by Minonk Wind, LLC. APFA indirectly owns 100% of the managing ownership interests in Minonk Wind, LLC through WP SponsorCo.

As part of APFA's acquisition of a controlling interest in Minonk Wind, LLC, Gamesa USA and Minonk Wind, LLC entered into an AMBOSA under which Gamesa USA provides asset management and balance of plant operations to the owner for a period of 20 years, and an operations and maintenance agreement, under which turbine operation, maintenance and repair services are provided at a contracted rate to the Minonk Wind Facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's turbine supply agreement.

Minonk Wind, LLC is party to a 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 an Energy Production Hedge. Ancillary services, including capacity and REC, are sold into the energy market in which the Minonk Wind Facility is registered.

(8) Senate Wind Facility

The Senate Wind Facility is a 150 MW wind energy facility located near Graham, TX, 200 km west of Dallas, TX. The Senate Wind Facility is owned by Senate Wind, LLC. APFA currently indirectly owns 100% of the managing ownership interests in Senate Wind, LLC through WP SponsorCo.

As part of APFA's acquisition of a controlling interest in Senate Wind, LLC, Gamesa USA and Senate Wind, LLC entered into an AMBOSA, under which Gamesa USA provides asset management and balance of plant operations to the owner for a period of 20 years, and an operations and maintenance agreement under which turbine operation, maintenance and repair services are provided at a contracted rate to the Senate Wind Facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's turbine supply agreement.

Senate Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 15 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under an Energy Production Hedge. RECs are sold into the energy market in which the Senate Wind Facility is eligible to sell such products.

(iv) Renewable Energy Credits

Renewable Energy Credits ("**RECs**") are tradable commodities representing the generation of 1 MWh 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. These targets range from 10-40%, with some initial deadlines having already passed, and some stretching to 2025 and beyond. At the current time 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, and the Bakersfield I Solar Facility, utilizes 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. 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 independent system operator.

(1) Ontario

The IESO was merged with the OPA in 2015. The combined organization operating as 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 Ontario Energy Board, 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 Federal Energy Regulatory Commission ("**FERC**"). The CAISO operates as a nonprofit 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 AC ground mounted photovoltaic solar energy facility located near Cornwall, Ontario, 100 km southeast of Ottawa.

On March 27, 2014, the Cornwall Solar Facility achieved commercial operation pursuant to the FIT contract between the project and the Ontario Power Authority (now the IESO) for a total investment of $47.6 million. The term of the PPA is 20 years with a fixed power purchase rate throughout the term.

(2) Bakersfield I Solar Facility

The Bakersfield Solar Facility is a 20 MW AC 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 Solar Facility is expected to reach COD in March 2015, generating fixed-price revenues via a 20 year Power Purchase Agreement with Pacific Gas & Electric. Total capital cost for the facility is approximately U.S. $58.5 million.

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. Often natural gas is used to produce both electricity and steam. 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. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel's energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel's energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

(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 Independent System Operator 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 and FERC. The California Independent System Operator 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**"). ISO-NE was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. 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.

Since May 1, 1999, ISO-NE has also administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants on an internet-based market system.

(iii) Material Facilities

(1) Sanger Thermal Facility

The Sanger thermal facility (the "**Sanger Thermal Facility**") is a 56MW natural gas-fired generating facility located in Sanger, California. 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. In 2012, APUC successfully completed a major upgrade at the Sanger Thermal Facility that involved an overhaul of the steam turbine, the replacement of the steam turbine generator, and the installation of a new 115kV transformer sized to manage the full output of the facility. The Sanger Thermal Facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

Output of the Sanger Thermal Facility is governed by the terms and conditions of a firm capacity and energy PPA with PG&E. The agreement has a term of 30 years, expiring in 2022, and calls for delivery of 38 MW of firm capacity.

Natural gas for the facility is delivered under the terms of a gas supply agreement with Constellation NewEnergy for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Gas above or below the nomination requirement can be bought or sold at the applicable spot prices.

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Algonquin Power Sanger LLC, Dyna Fibers Inc. leases a portion of the facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the Sanger Thermal Facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to PG&E on an annual basis.

(2) Windsor Locks Thermal Facility

The Windsor Locks Thermal Facility has a total installed capacity of 71 MW. 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 is owned by Algonquin Power Windsor Locks LLC.

The Windsor Locks Thermal Facility supplies thermal steam energy and the majority of the output from the Solar Titan combustion turbine to 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. Each REC is then sold into the ISO-NE market.

APUC's subsidiary, Windsor LLC, has entered into an agreement with a natural gas retailer and wholesale supplier to provide gas to the Windsor Locks Thermal Facility as required to meet the Ahlstrom ESA obligations and the market dispatch requirements.

(iv) Renewable Energy Credits

RECs are tradable commodities representing the generation of 1 MWh 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. These targets range from 10-40%, with some initial deadlines having already passed, and some stretching to 2025 and beyond. At the current time the Windsor Locks Thermal Facility produces and sells RECs through bilateral contracts.

Business Development

(i) Strategy

The Development Division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APUC's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. It utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors. APUC's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project 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 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 construction will proceed.

The prevailing economic climate has also created opportunities to acquire operating assets or third party development projects at various stages of development on terms that require the experience and financial resources that the company has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

(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 Ontario and Saskatchewan are expected to present the most immediate opportunities for Algonquin. The Ontario government, through the Independent Electricity System Operator ("**IESO**") is conducting a process to receive Requests For Proposals ("**RFP**"s) for up to 300 MW of wind power, up to 140 MW of solar power and up to 50 MW of hydro power with responses due in 2015. In 2014, Algonquin was one of a number of parties that were qualified to participate in future RFPs. Nova Scotia also continues to offer its community feed-in-tariff 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. Absent a further legislative extension, in order for a renewable power facility to be eligible for PTCs, construction of the facility must have been commenced by December 31,

2014 and, unless completed prior to January 1, 2017, must be continuously maintained until the facility is placed in service (all determined in accordance with guidelines published by the IRS). Under current law, ITCs are scheduled to expire or to be reduced (depending on the energy source) for facilities placed in service after December 31, 2016, with the ITC for solar electric generation decreasing from 30% to 10% of eligible capital costs. However additional 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 renewable portfolio standards (RPS), which vary between states. As of September 2014, 30 states have adopted binding RPS targets, and 9 have taken on voluntary targets. These targets range between 10% and 40% of installed capacity or retail sales, to be achieved between 2015 and 2028.

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

(iii) Current Development Projects

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

Project Name	Location	Size (MW)	Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction						
Morse Wind Project[1]	Saskatchewan	23	$ 81.3	2015	20	104.0
Bakersfield I Solar Project[1,2]	California	20	$ 67.9	2015	20	53.3
Total Project in Construction		**43**	**$ 149.2**			**157.3**
Projects in Development						
Odell Wind Project[1,3]	Minnesota	200	$ 374.5	2015/16	20	814.7
Val Eo Wind Project[1,4,5]	Quebec	24	$ 70.0	2016/17	20	66.0
Bakersfield II Solar Project[1,6]	California	10	$ 31.3	2016	20	26.5
Amherst Island Wind Project[1]	Ontario	75	$ 260.0	2016/17	20	235.0
Chaplin Wind Project[1]	Saskatchewan	177	$ 340.0	2017/18	25	720.0
Total Projects in Development		**486**	**$ 1,075.8**			**1,862.2**
Total in Construction and Development		**529**	**$ 1,225.0**			**2,019.5**

1 PPA Signed.

2 Total cost of the project is expected to be approximately $58.5 million in U.S. dollars.

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

4 The Val Eo Wind Project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2015 and the101 MW 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.

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

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

(1) Morse Wind Project

The Morse Wind Project is comprised of three contiguous projects with 25 MW of aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

Based on the award of 25 MW under Saskatchewan's Green Options Partner Program, SaskPower has offered the Generation Group a 20 year contract for the procurement of 23 MW of wind generation to match the nameplate capacity of the proposed turbines.

The Generation Group executed an asset purchase agreement with a local developer, Kineticor, to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by the Generation

Group independently. All of the individual projects comprising the Morse wind project were selected by SaskPower in accordance with the SaskPower Green Options Partners Program.

The turbine supply agreements have been executed with Siemens and the Balance of Plant Engineering, Procurement and Construction agreement has been signed. The turbine placement has been finalized and registered land leases have been executed with the landowners. Installation of access roads and foundations are completed, and turbine delivery commenced in January 2015. All turbines have been erected, and the project is expected to be operational by March 31, 2015. Currently, four out of 10 turbines have been commissioned and are generating energy which is being sold to SaskPower at 100% of the PPA rate.

(2) Bakersfield I Solar Project

The Generation Group has entered into an agreement for the continuing development of a 20 MWac solar powered generating station located in Kern County, California. Following commissioning, the Bakersfield Solar Project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement with expected first full year revenues of U.S. $4.7 million. The Generation Group has entered into a partnership agreement with a third party (the " **Tax Partner**") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. The Tax Partner will contribute U.S. $22.0 million to the project with the remaining of the total estimated cost of U.S. $58.5 million to be funded by the Generation Group.

Construction of the project commenced in the second quarter of 2014 and was placed in service on December 30, 2014. Testing to ensure the plant will be ready and available for commercial operations was conducted and confirmed by the Generation Group and independent engineers. Final construction efforts continue, with the project expected to reach full commercial operation in the first quarter of 2015. Final construction efforts are nearing completion and the project is currently generating electricity which is being sold to PG&E at prevailing market rates until the project reaches COD early in the second quarter of 2015.

(3) Odell Wind Project

The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20 year PPA, all energy, capacity and renewable energy credits 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 is expected to begin in the second quarter of 2015, with total costs estimated at U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in late 2015 or early 2016.

(4) Val-Eo Wind Project

Phase one of the Val-Eo Wind Project is located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Eo wind cooperative formed by community based landowners and the Generation Group. The first 24 MW phase of the project is expected to be comprised of eight wind turbines, producing approximately 66.0GW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in 2015 with commercial operations commencing in 2016. The second phase of the project would entail the development of an additional 101 MW. The permitting and the Environmental Impact Assessment are ongoing with a projected provincial minister's decree in early 2015.

The Generation Group's equity interest in the project is subject to final negotiations with the Val-Eo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24MW phase of the Val-Eo 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.

Commission de Protection du Territoire Agricole Quebec ("CPTAQ") approval has been received for 8 turbine locations, roads, and the collection system. Land option agreements have all been secured, and the process of converting these options is currently underway. Proposals for the procurement of the substation and balance of plant have been received and evaluated. The final construction schedule is pending the signing of the turbine supply agreement.

(5) Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MW project adjacent to the Generation Group's 20 MW Bakersfield I Solar Project in Kern County, California, which is currently under construction.

The 10 MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20 MW Bakersfield I Solar Project. Construction of Bakersfield I Solar is nearing completion, with commercial operations expected to occur in the first quarter of 2015.

The total project cost for Bakersfield II Solar of approximately U.S. $27 million will be funded with a combination of senior debt, common equity, and contributions from tax equity investors. Consistent with financing structures utilized for U.S. based renewable energy projects including Bakersfield I Solar, it is anticipated that Bakersfield II Solar will source financing in the amount of approximately 40% of the capital costs from certain tax equity investors.

Construction of Bakersfield II Solar is anticipated to commence in mid-2015 following receipt of local permits and finalization of necessary construction contracts, subject to approval by the APUC board of directors. Commercial operation is targeted to occur in the first half of 2016.

(6) Amherst Island Wind Project

The Amherst Island Wind Project is located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the IESO, formerly the OPA, as part of the second round of the FIT program.

The Amherst Island Wind Project is currently contemplated to use Class III wind turbine generator technology. The available wind resource is forecast to produce approximately 235 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Final negotiation on the turbine supply agreement is ongoing. Total capital costs for the facility are currently estimated to be $260.0 million, and engineering, procurement and construction contractor selection is underway. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

The Renewable Energy Approval ("**REA**") application was submitted in April 2013 and posted to the environmental registry in early January 2014 and has been undergoing technical review. Changes to the project design have been initiated to optimize construction and project performance, which will require a modification of the application documents. Once the REA is issued in final form, it may be appealed by interested parties within 15 days of its release. If the REA is appealed, the appeal process is expected to take up to 6 months. Other permitting processes are progressing according to schedule. The project has a planned construction time frame of 12 to 18 months with most of the construction expected to occur in 2016.

(7) Chaplin Wind Project

In the first quarter of 2012, the Generation Group entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

The project will be split into two phases where Phase I will approximate 35 MW of the total project and is currently planned to be operational in 2017. The first phase will involve installing test turbines to prove the project viability. The second phase, the infill construction phase, will only commence provided the results of the first phase are successful.

The total facility will be constructed at an estimated capital cost of $340.0 million and consist of approximately 77 multi-megawatt wind turbines. In the total project's first full year of operation, the Generation Group expects to achieve EBITDA of $36.5 million. The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of its favorable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

In March 2014, after review of the Project Proposal Environmental Assessment and Supplemental documentation (including the preliminary proposed layout), the project was deemed a development by the Environmental Assessment Branch. An additional detailed environmental review is currently being completed. It is anticipated that the Environmental Assessment documentation will be submitted to the government in the first quarter of 2015. The expected capital costs of the project are approximately $340.0 million. The Generation Group anticipates entering into a partnership and development agreement using a similar structure to what was utilized in the development of the Red Lily I Facility, in order to facilitate the development of the project and to optimize returns.

(8) Ontario RFP Qualification

The Generation Group has qualified for participation in the anticipated 2015 Large Renewable Procurement I process with the IESO. The Generation Group may submit offers into the expected RFP for up to 100 MW of solar power and up to 100 MW of wind power. The IESO is expected to award up to 140 MW of solar projects and 300 MW of wind projects. RFP bids are due by June 2015, with successful bidders being announced in August 2015.

(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 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 Generation Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Generation Group in-house.

The energy from wind aspect of the business of the Generation Group requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to the Generation Group in-house. On a more general level, the production of energy from all facilities of the Generation Group requires specialized skill and knowledge, and the 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 US Department of Energy ("**USDOE**") has suggested that in a competitive marketplace, utilities and energy marketers will utilize green power pricing to strengthen their image with their customers and build customer loyalty. Further, the 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 is generally more expensive than traditional forms of generated power, but costs have been decreasing with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, renewable portfolio standards, and improved equipment capacity factors, wind energy is approaching 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 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 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) Energy Marketing of the Tinker Generating Facility

Demand for energy sold to retail customers in the Maritime Region is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served is located in a "winter peaking" region.

(iv) Solar Power Generating Facilities

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

3.1.6 Customers

The Generation Group's businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2014, APUC's businesses' revenues were derived as follows: PJM Interconnection LLC - 5.2%; Manitoba Hydro - 3.3%; Hydro Quebec – 2.4%; Connecticut Light and Power - 2.5%.

3.2 Distribution Group

3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water Distribution and waste water 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 Waste Water 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 Convenience and Necessity ("**CC&N**") which imposes an exclusive right and duty to serve in the service territory. A CC&N 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 company'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 CC&N 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 the company's customers. The agency must balance the interests of the rate payers 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 the company's customers. The agency must balance the interests of the rate payers 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 fee, reconnects, etc.

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 Company's water and wastewater facilities are located in the United States of America in the states of Arizona, Texas, Missouri, Arkansas, and upon closing of the Park Water acquisition, 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 Company 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. A summary of the rates and tariffs for the wastewater treatment and water distribution business unit 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 the 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 Arkansas Public Service Commission ("**PSC**") is 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 California Public Utilities Commission ("**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., that jurisdiction of drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The California State Water Resources Control Board is the primary regulator for all discharge permits from drinking water systems in California.

(5) Montana

The Montana Public Service Commission ("**MNPSC**") 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 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 water distribution and wastewater treatment facility (" **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 21,100 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 80% of design capacity. The LPSCo System supplies Class "A+" effluent to a number of local golf courses in the area. The LPSCO System's largest 10 connections represent approximately 11.5% of its total annual sales of approximately U.S. $23.1 million. Its largest customers are the City of Goodyear and an elementary school.

Rate Case

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission 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 commission approved a $1.8 million increase in rates effective on May 1, 2014.

Financing

The LPSCo System currently has outstanding indebtedness to the City of Goodyear in the amount of U.S. $10.7 million in respect of which the City of Goodyear has acted as a conduit issuer of a like amount of Industrial Development Authority bonds. The bonds consist of two series, both fully amortizing over a 30 year term. The first series was issued in 1999, has a principal amount as of December 31, 2014 of U.S. $2.9 million bearing an average interest rate of 5.95%. The second series was issued in 2001 with a principal amount as of December 31, 2014 of U.S. $6.9 million and bearing an average interest rate of 6.75%. As partial security for these bonds, the LPSCo System is required to hold funds in a restricted, interest bearing, investment account. The balance of this account at December 31, 2014 was U.S. 6.6 million.

(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.

The Rio Rico System serves approximately 6,800 water and 2,200 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.

(4) 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 Public Service Commission and has a franchise agreement with the City of Pine Bluff, Arkansas.

Connection Base

The Pine Bluff Water System serves a population of over 50,000 people comprising approximately 17,800 connections. During the year ended December 31, 2014, the Pine Bluff Water System's largest 10 connections represent approximately 38.1% of its total annual sales of approximately U.S. $8.8 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 APSC seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. An Order and new rates are expected in the second quarter of 2015.

(5) Acquisition of the Park Water System

In 2014 the company announced that it has entered into an agreement to purchase the regulated water distribution utility Park Water Company ("**Park Water System**"). 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.

The acquisition requires the approval of both the CPUC and the MNPSC. An approval application was filed on November 24, 2014 with the CPUC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to acquire the two water utilities located in California owned by the Park Water Company, Park Central Basin and Apple Valley Ranchos Water. A decision on the California application is expected in the third quarter of 2015. An approval application was also filed on December 15, 2014 with the MNPSC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to effectively acquire Mountain Water Company. A decision on the application is expected in the fourth quarter of 2015.

The water utility in Western Montana serving the municipality of Missoula is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude, whether the city of Missoula will be successful in its condemnation efforts and, if successful, the amount of compensation to be paid to APUC.

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 and New Hampshire 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 Company operates electrical distribution systems in the states of California and New Hampshire under a cost-of-service methodology. The utilities use an historical test year, pro-formed for known and measurable changes, in the establishment of their rates. 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 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 Company 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 Company's Distribution Group's 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 (" **PTAM**") 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 $3.0 million or $36.0 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, 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.

(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 48,300 connections.

Connection Base

CalPeco Electric System's connection base of approximately 48,300 connections is primarily residential with large commercial accounts limited to less than 20% 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 14.6% of its total annual sales of approximately U.S. $73.2 million. Its largest customers are major ski resorts and large region school district.

Rate Case

The CalPeco Electric System's most recent rate case was filed and settled in 2012. The CPUC's decision adopts an all-party settlement for the test year of 2013. The settlement includes a combined increase in both Base Rates and the ECAC of $3.7 million in 2013; a test year rate base of $121.2 million; a 2013 return on equity of 9.9%, based upon a capital structure of 48.5% debt and 51.5% equity, using a long-term debt cost of 5.5% and resulting in an overall rate of return of 7.8%. Rates were implemented on January 1, 2013.

Another element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account was agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility.

The next general rate case application for the CalPeco Electric System is expected to be filed in Q2 2015, and will be based on a historical test year of calendar 2014, with pro-forma adjustments for known and measurable changes in calendar 2015 and 2016.

Kings Beach Generation

The CalPeco Electric System has a local-area emergency backup generation facility at Kings Beach in Placer County, California. The facility consists of six new 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. Any non-preventative maintenance expenditures that may occur during the first five years of operation will be fully covered by the Manufacturer's warranty.

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 will be addressed by an annual filing.

PPA

The CalPeco Electric System entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at rates NV Energy's "system average cost". The PPA was effective on January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA.

NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC renewable portfolio standards requirements, and the PPA is designed to enable the CalPeco Electric System to comply with the associated RPS reporting requirements.

The CalPeco Electric System is currently investigating options to ensure the continuation of electricity supply for its customers that will continue to be secure, reasonably-priced, and in compliance with RPS requirements, beyond the existing term of this 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 44,600 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 38,000 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 11.9%

of its total annual sales of approximately $113.6 million. Its largest customers are a world renowned medical facility and an Ivy League educational institution.

Rate Case

In the first quarter of 2013, the Granite State Electric System filed a rate case with the NHPUC which sought 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 commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014. The rates came into effect April 1, 2014.

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.

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 Company 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 Company 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 Company 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 Company's Distribution Group' 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, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety.

Customer natural gas bills can be broken down into two primary components: delivery and commodity charges. The delivery charges portion of the bill is designed to recover those costs associated with the delivery of gas through the distribution system (i.e. operating costs, system maintenance, safety and inspection programs, customer service, metering, billing, etc.) and is regulated by the NHPUC. The rates are based on reasonable and prudent expenses incurred in providing service and a reasonable rate of return on the gas utility's plant investment. It is through the allowed rate of return on plant investment that a gas utility has the opportunity to earn a return.

The commodity charge is for gas supply purchased by the gas utility on behalf of the customer and is set twice each year (summer and winter periods) with all gas supply costs (i.e., commodity costs, interstate pipeline transportation, underground storage contracts, etc.) factored into the rate. While the interstate pipeline rates are regulated by the FERC, natural gas and propane are unregulated commodities. The EnergyNorth Gas System is allowed to pass these costs onto customers on a dollar for dollar basis, with no mark up. NHPUC Staff conducts regular audits and prudence reviews of all gas supply decisions and related costs. Following a hearing on the issues, the NHPUC sets Cost of Gas Rates.

(2) Illinois

The Company's Illinois operations are regulated by the Illinois Commerce Commission (" **ICC**").

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.

(3) Iowa

The Company's Iowa operations are regulated by the Iowa Utilities Board (" **IUB**").

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.

(4) Missouri

The Company's Missouri 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 Purchased Gas Adjustment.

(5) Georgia

The Company's Georgia operations are regulated by the Georgia Public Service 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 Purchased Gas Adjustment.

(6) Massachusetts

The Company'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.

Customer natural gas bills can be broken down into two primary components: delivery and commodity charges. The delivery charges portion of the bill is designed to recover those costs associated with the delivery of gas through the distribution system (i.e. operating costs, system maintenance, safety and inspection programs, customer service, metering, billing, etc.). A portion of these delivery charges are established during a rate case proceeding, and are reflective of prudent and reasonable expenses incurred in providing service, and a reasonable rate of return on the plant investment. A second portion of the delivery charges are recovered through the Local Distribution Adjustment Factor.

The commodity portion of the bill, or Gas Adjustment Factor, is designed to recover costs associated with gas supply purchased for the benefit of customers (i.e., commodity costs, interstate pipeline transportation, underground storage, peaking shaving costs). A GAF filing is made with the MDPU twice annually (summer and winter periods). While the interstate pipeline rates are regulated by the FERC, natural gas is an unregulated commodity. The Company's is allowed to pass these costs onto customers on a dollar for dollar basis. GAF filings are fully reviewed by MDPU staff prior to establishment of the GAF rates.

(iii) Material Facilities

(1) EnergyNorth Gas System

The EnergyNorth gas system (the "**EnergyNorth Gas System**") is a regulated natural gas utility providing natural gas distribution services to approximately 92,100 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 82,500 connections, while the commercial and industrial customer base represents approximately 9,600 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 2.2% of its total annual sales of approximately U.S. $152.8 million. Its largest customers are a technology company and multiple public works facilities.

Rate Case

On August 1, 2014, the EnergyNorth Natural 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 consists of U.S. $13.4 million of permanent base distribution rates and a step increase of U.S. $2.65 million for investments made during a pro forma period. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Company's ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increases effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates.

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.

(2) Midstates Gas System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 85,900 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 23,600 connections in Illinois, 4,500 connections in Iowa and 57,800 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of the 85,900 connections, approximately 76,600 (89%) are residential connections, while 9,300 (11%) 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 7.2% of its total annual sales of approximately U.S. $81.8 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.

(3) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services to approximately 58,100 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 53,800 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 5.7% of its total annual sales of approximately U.S. $70.4 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, 2013, the Peach State Gas System filed an application for an increase in revenue of U.S. $4.9 million in its annual GRAM filing with the GPSC. In January 2014, the Company 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. $3.9 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). Commission approval was received on December 4, 2014.

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 program is due to be completed in two years at which time the rate base remaining under this program will be rolled into the annual GRAM filing.

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 Purchased Gas Adjustment ("**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.

(4) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 55,900 customers in six communities located in the southeastern portion of Massachusetts.

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 52,200 connections, while the commercial and industrial customer base represents approximately 3,700connections. 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 Company (Spectra Energy) transmission system. The New England Gas System's largest 10 connections represent approximately 4.1% of its total annual sales of approximately U.S. $73.2 million. Its largest customers are waste management and textile companies.

Rate Case

New England Gas System's last rate case was filed with the MDPU on September 16, 2010 and docketed as MDPU-10-114. On March 31, 2011, the MDPU issued its order awarding the New England Gas System an increase in base distribution revenues of $5.1 million. In addition the MDPU granted approval of a targeted infrastructure replacement factor to facilitate recovery of costs associated with its aging infrastructure replacement program, and a revenue decoupling mechanism proposed by the New England Gas System to mitigate the effects of lost revenue associated with energy efficiency and to stabilize earnings variability associated with weather.

The next general rate application for the New England Gas System is expected to be filed in Q2 2015, and will be based on a historical test year of calendar 2014, with pro-forma adjustments for known and measurable changes in calendar 2015.

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 >5%.

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, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7.0, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6.0, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.

3.2.3 Specialized Skill and Knowledge

The Distribution 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 Distribution Group will typically retain the existing employees with such specialized skill and knowledge.

In addition, the Distribution 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 Distribution Group's businesses have geographic monopolies in their service territories and are therefore insulated from competition. The Distribution 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 Distribution 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.

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 $3.0 million or $36.0 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.

(iii) Natural Gas Systems

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

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

3.2.6 Customers

The Distribution Group's businesses derive their revenues from a diverse residential, commercial and industrial customer base. For the twelve months ended December 31, 2014, electricity sales and distribution were approximately 50% from residential customers and 50% from commercial and industrial customers; natural gas sales and distribution were approximately 65% from residential customers and 35% from commercial and industrial customers; and water and waste water sales were approximately 77% from residential customers and 23% from commercial and industrial customers.

3.3 Transmission Group

3.3.1 **Regulatory Regimes -** Pipeline Transmission **Systems**

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certificates all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an Open Access transmission tariff 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.

3.3.2 Description of Operations

Natural Gas Pipeline 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.

(ii) Investments

(1) Northeast Expansion Project

On November 24, 2014, APUC announced its agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form Northeast Expansion LLC to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "**Project**"), which will be operated by Tennessee Gas Pipeline Company, L.L.C. (" **Tennessee**") . The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with commercial operations occurring by late 2018. Under this framework, Tennessee, as Operator, would be regulated by the FERC.

3.4 Business Associations with APMI and Senior Executives

Ian Robertson and Chris Jarratt (" **Senior Executives**"), respectively Chief Executive Officer and Vice-Chair of APUC, are indirect shareholders of Algonquin Power Management Inc. ("**APMI**"), the former manager of the Company and several related affiliates (collectively the " **Parties**"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee (" **Independent Board Committee**") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to the valuations of the generating assets, tax and legal matters.

The process, initiated in 2011, was completed in November 2013 and all related party transactions, except as noted below, between APUC and the Parties have been addressed to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

Due to and from related parties

Effective December 31, 2013, APUC paid the Parties $1.8 million in connection with outstanding fees and the Parties paid APUC $0.8 million in connection with reimbursement of expenses. As at December 31, 2014, $0.047 million (2013 - $0.047 million) remains due from Algonquin Power Systems Ltd., a corporation partially owned by the Senior Executives.

Equity interests in Rattle Brook Hydro, Long Sault Hydro, and BCI Thermal Facilities

The Parties own interests in three power generation facilities in which APUC also has an interest. A brief description of the facilities is provided as follows:

- Rattle Brook is a 4 MW hydroelectric generating facility (the "**Rattle Brook Hydro Facility**") constructed in 1998 in which APUC owns a 45% interest and Senior Executives hold an equity interest in the remaining 55%.
- Long Sault Hydro Facility is an 18MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in Long Sault Hydro Facility by way of subscribing to two notes from the original partners. One of the original partners, an affiliate of APMI, is entitled to receive 5% of the equity cash flows commencing in 2014.
- Brampton Cogeneration ("**BCI Thermal Facility**") is an energy supply facility which sells steam produced by the Energy from Waste Thermal Facility ("**EFW Thermal Facility**"). In 2004, APMI acquired 50 Class B partnership units in the BCI Thermal Facility entitling them to 50% of the cash flow above 15% return on the investment.

Effective December 31, 2013, APUC acquired the Parties' shares of APCI which owns the partnership interest in the 18 MW Long Sault Hydro Facility and the partnership interest in the BCI Thermal Facility plant for an amount equal to $3,780. As APUC already consolidates Long Sault Hydro Facility as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10,692 in regards to tax attributes acquired with the partnership interests and an adjustment of $14,601 to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4 MW Rattle Brook Hydro Facility to the Parties for gross proceeds $3.4 million for a loss on sale, net of tax, of $0.4 million.

APUC earned a fee of $0.4 million from APCI during the year ended December 31, 2013 related to settlement of the related party transactions.

St. Leon LP Units

Third party investors, including Senior Executives, previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership, which is the legal owner of the St. Leon Wind Facility.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units (note 11) including 36 units held indirectly by Senior Management. The Series C preferred shares provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the

Independent Board Committee. As of January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2014 were $0.3 million (2013 - $0.3 million). In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease for nominal consideration. There is no further related party matter in relation to an office lease.

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $0.5 million. As at December 31, 2013, the Independent Board Committee and the Parties agreed that all future utilization of chartered aircraft would be undertaken through a third-party charter operator at fair market value and under arrangements in which the Senior Executives have no interest. Final arrangements in this regard had not been completed as at December 31, 2014. During the year ended December 31, 2014, APUC reimbursed direct costs in connection with the use of the aircraft of $0.7 million.

Trafalgar

The Company owns 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 affiliate of APMI moved to foreclose on the assets. Subsequently, Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2.0 million in legal fees prior to 2004.

In 2004, the Board reimbursed APMI $1.0 million of the total third party legal fees (which to that point totalled $2.0 million), and APUC agreed to fund future legal fees, third party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

A member of the Board is an executive at Emera. Related Party Transactions between APUC and Emera are discussed below:

- For the year ended December 31, 2014, the Company sold electricity to Maine Public Service Company (" **MPS**"), a subsidiary of Emera, amounting to U.S. $5.8 million (2013 - U.S. $6.0 million). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3.0 million and a letter of credit in an amount of U.S. $0.1 million, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine. For the year ended December 31, 2014, the Company purchased natural gas amounting to U.S. $5.0 million (2013 - U.S. $1.3 million) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1.0 million to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks Thermal Facility. There has not been any transaction under this contract in the last three years.

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

Other

A spouse of one of the Senior Executives provided market research consulting services to certain subsidiaries of the Company. During the year ended December 31, 2014, APUC paid $0.192 million (2013 - $0.045 million) in relation to these services.

3.5 Principal Revenue Sources

As at March 30, 2015, APUC owned, directly or indirectly, debt, equity and royalty and other interests in forty-one renewable generation facilities and four thermal generation facilities including those identified in "Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments", two electrical distribution utilities, six natural gas distribution utilities, 1 propane gas distribution utility, and 23 water distribution and wastewater utilities.

For the year ended December 31, 2014, APUC derived approximately 21.4% of its revenues from its interests in power generation facilities (26.7% in 2013), 21.9% of its revenues from electrical distribution utilities (24.6% in 2013), 47.3% of its revenues from natural gas distribution utilities (38.6% in 2013), and 7.0% of its revenues from its interests in water distribution and wastewater utilities (8.5% in 2013).

The purchase of electricity and natural gas by the company'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 company 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 31.2% of its revenues from its

interests in power generation facilities (38.3% in 2013), 16.5% of its revenues from electrical distribution utilities (17.1% in 2013), 35.4% of its revenues from natural gas distribution utilities (27.7% in 2013), and 12.7% of its revenues from its interests in water distribution and wastewater utilities (14.2% in 2013).

3.6 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, 2014. 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 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.

3.7 Employees

APUC's Executive Management Group consists of seven individuals including the Presidents of the Generation Group and the Distribution Group. The Generation Group employs a total of 157 employees. With the exception of 5 employees at the Tinker Hydro Facility, the employees of the Generation Group entities are non-unionized.

The Distribution Group employs a total of 1,104 employees. The Distribution Group employees are non-unionized with the exception of: 58 employees at the CalPeco Electric System, 43 employees at the Midstates Gas System, 157 employees at the EnergyNorth Gas and Granite State Electric System, and 67 employees at the New England Gas System.

3.8 Foreign Operations

As at December 31, 2014, approximately 78% of EBITDA and 77% of cash flow are generated from operations located in the United States and are denominated in U.S. Dollars.

3.9 Economic Dependence

The largest customer on a percentage basis is PJM Interconnection LLC, which totalled 5.2% of gross revenues in the year ended December 31, 2014. PJM Interconnection maintains an Aa3 rating issued by Moody's and receivables from PJM Interconnection are invoiced monthly and generally collected within 14 days.

The second largest customer on a percentage basis is Manitoba Hydro which totalled 3.3% of gross revenues in the year ended December 31, 2014. This customer maintains an Aa1 rating issued by Moody's and receivables are invoiced monthly and generally collected within 20 days.

The third largest customer is Quebec Hydro, totaling 2.4% of gross revenues in the year ended December 31, 2014. This customer maintains an Aa2 rating issued by Moody's and receivables are invoiced monthly and generally collected within 20 days.

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.

3.10 Social or Environmental Policies

APUC has formal policies and procedures that support its commitment to corporate responsibility. APUC's Code of Business Conduct and Ethics is the foundation of the Corporation's corporate responsibility 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 a declaration annually, 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 region. 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 Corporate Responsibility (" **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 Company'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.

3.11 Credit Ratings

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

	S&P		DBRS	
	2014	2013	2014	2013
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)
CalPeco - Senior unsecured notes	-	-	BBB	BBB

[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

DBRS

DBRS rates debt instruments and issuers with ratings ranging from "AAA", which represents debt instruments and issuers of the highest credit quality, to "D", which 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. Long-term debt rated "BBB" category by DBRS are of 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

There were no changes in DBRS’s ratings for APUC or its subsidiaries in 2014 and 2013.

S&P

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. An obligor rated ‘BBB’ has 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.

There were no changes in S&P’s ratings for APUC or its subsidiaries in 2014 and 2013.

4. 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. Key risks and associated mitigation strategies are reviewed by the Executive Risk Steering Committee on a monthly basis and presented to the Board of Directors on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, security (physical and cyber), operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

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

The development and execution of risk treatment plans are actively monitored by the ERM team through a centralized risk register software application. APUC’s internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and regularly reported to the Board on a quarterly basis and more frequently if and when necessary. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Executive Risk Steering Committee and the Board of Directors for consideration.

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

The following information is a summary only of certain risk factors relating to APUC’s businesses and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF and the documents incorporated by reference herein.

4.1 Financial Risk Management

APUC proactively manages the risk exposures of its subsidiaries in a prudent manner. The Generation and Distribution Groups maintain industry standard insurance on all of their facilities, including property and casualty, boiler and machinery, workers' compensation, automotive, and liability insurance. The company has also initiated a number of programs and policies including currency and interest rate hedging strategies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

4.1.1 Market Price Risk

(i) Generation Group

The Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to mechanical failures, production shortfalls may be such that the Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge. Power hedges are typically settle and are based on prices observed at a central hub. Certain power purchase contracts can be based on a price of power delivered at a specific node. Due to factors such as transmission congestion, electricity supply and electricity demand, there can be a difference between the hub price and the node price (otherwise known as basis difference) which can vary over time and be different than the original assumptions used at the onset of the hedge; these differences can be material. The Generation Group attempts to mitigate this risk by entering into hedges where there are minimal congestion constraints between nodes and hubs, paying for financial transmission rights at a fixed price.

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

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

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

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

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

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

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2014, the Generation Group had not entered into any such hedges.

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

(ii) Distribution Group

The Distribution Group does not have exposure to market price risk as rates charged to customers are stipulated by the respective regulatory bodies based on rate case proceedings which are intended to provide for a recovery of prudently incurred operating costs, as well as a recovery of and return on invested capital.

4.1.2 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 78% of EBITDA in 2014 and 77% 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 $22.8 million ($0.10 per share) on an annual basis.

In light of the currency profile of its operations, APUC changed the currency of its dividend to U.S. dollars in the third quarter of 2014. APUC further manages currency risk through the matching of U.S. long term debt to finance its U.S. operations, thereby creating a natural hedge for the operating profit vis-à-vis financing cost. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. APUC may from time to time enter into short term foreign currency derivative contracts to hedge exposure of anticipated transactions denominated in a foreign currency.

4.1.3 Commodity Price Risk

(i) Generation Group

The Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Distribution Groups is exposed to energy price risk within the Electric 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 174,000 MW-hrs in fiscal 2015, of which 90,000 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 80,000 MW-hrs of its energy requirements at the ISO-NE summer spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 174,000 MW-hrs. The risk associated with the expected market purchases of 80,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 90% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $65 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.5 million on an annualized basis.

(ii) Distribution Group

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 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 takes on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

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

The 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 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, and have implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

4.1.4 Tax Risk and Uncertainty

The Company is subject to tax audits from various government and regulatory agencies on an ongoing basis. As a result, from time to time, taxing authorities may disagree with the positions and conclusions taken by the Company in its tax filings or legislation could be amended or interpretations of current legislation could change, any of which events could lead to reassessments. These reassessments could have a material impact on the Company in future periods and could impact the return to shareholders.

Unit Exchange Transaction

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

Subsequent to the Balance Sheet date, APUC received a proposal letter from the Canada Revenue Agency (" **CRA**") which outlines its intention to challenge the tax consequences of APUC's 2009 Unit Exchange. CRA is seeking to apply the acquisition of control rules or the general anti-avoidance rules of the Income Tax Act (Canada) the effect of which would be to deny APUC of the benefit of the tax attributes assumed as part of the Unit Exchange Transaction.

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17.5 million. Additionally, assuming the 2014 taxation year will be

similarly reassessed, a further payment of approximately $3.1 million would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar notice of reassessment for such years and APUC were to appeal it.

Should APUC be successful in defending its position, all such payments plus applicable interest, will be refunded to APUC. If the CRA is successful, APUC will be required to pay the balance of the taxes assessed (plus applicable interest and any applicable penalties).

APUC has 90 days from the date of any Notice of Reassessment to prepare and file a Notice of Objection, which would be reviewed by the CRA's appeals division. If the CRA appeals division does not allow APUC's initial appeal, APUC has the option to file its case with the Tax Court of Canada. APUC anticipates that legal proceedings through the various tax courts could take approximately two to four years.

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from $nil to $45.0 million.

The impact of the proposal on APUC's tax provision has been considered by management; however, management continues to believe that the most likely outcome has not changed and it is more likely than not, that APUC will be successful in defending its position. On this basis, APUC's 2014 financial statements do not include the impact of a potential reassessment. Until the matter is resolved with CRA, or should new facts arise that would result in a change to management's assessment of the most likely outcome, any future deposit tax payments made by APUC will be recorded to the balance sheet and will not impact either adjusted funds from operations or net earnings.

On a consolidated basis, APUC and its Canadian subsidiaries have tax attributes that are available to reduce or eliminate cash taxes. Should the CRA ultimately be successful in the appeal process, APUC will seek to refile prior year tax returns and accelerate the use of such tax attributes to minimize any actual cash taxes that would otherwise be owed as a result of the reassessment of the tax consequences of the Unit Exchange.

4.1.5 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. The APUC Facility has no amounts outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The Generation Credit Facility had $23.4 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Distribution Credit Facility had $23.9 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Generation Group is party to an interest rate swap whereby, the group pays a fixed interest rate of 4.47% on a notional amount of $60.5 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur. As a result, a 100 basis point change in the variable rate would impact derivative gains/losses by $0.01 million.
- The Shady Oaks Senior Debt Facility had $88.2 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.9 million annually.

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. The interest rate swap, although not designated as a hedge, serves to partially offset interest rate movements against the variable pay portion of the Company's debt.

To mitigate refinancing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter the Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment will apply to this transaction. Consequently, changes in fair value, to the extent deemed effective, will be recorded into Other Comprehensive Income.

4.1.6 Credit/Counterparty Risk

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

APUC assesses the credit risk of default by counterparties to its long term power purchase contracts based primarily, but not entirely, on the credit ratings of its counterparties. Approximately 84.7% of the Generation Group's revenues are earned from large utility customers having a credit rating of Baa1 or better by Moody's Rating Services or BBB+ or higher by S&P Rating Services. The following chart sets out the Generation Group's significant customers, their credit ratings and percentage of total revenue associated with the customer:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percent of Divisional Revenue
Generation Group - Renewable Energy			
PJM Interconnection LLC	Aa3	49.0	33.6%
Manitoba Hydro	Aa1	31.1	21.4%
Hydro Quebec	Aa2	22.6	15.5%
Ontario Electricity Financial Corporation	Aa2	17.8	12.2%
Emera Maine [2]	N/A	8.0	5.5%
Total – Renewable Energy		**$ 128.5**	**88.2%**
Generation Group - Thermal Energy			
Pacific Gas and Electric Company	Baa1	19.8	46.1%
Connecticut Light and Power	Baa1	23.2	53.9%
Total – Thermal Energy		**$ 43.0**	**100.0%**
Total – Generation Group		**$ 171.5**	**84.7%**

[1] Ratings by Moody's or Standard & Poor's as of February 2015.

[2] Maine Public Service is a subsidiary of Emera Inc. which has a corporate rating of BBB+.

The remaining revenue is primarily earned by the Distribution Group. In this regard, the credit risk attributed to the Distribution Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $5.9 million which is spread over approximately 97,000 connections, resulting in an average outstanding balance of approximately $60 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $62.0 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. 24.3 million. The natural gas and electrical utilities, respectively, derive over 65% and 50% of their revenue from residential customers.

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

4.1.7 Liquidity Risk

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

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

As at December 31, 2014, APUC and its subsidiaries had a combined $485.9 million of committed and available credit facilities remaining and $9.3 million of cash resulting in $495.2 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.35 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for

amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of common share dividends paid during the year ended December 31, 2014, cash provided by operating activities exceeded common share dividends declared by 2.2 times and Adjusted funds from operations exceeds common share dividends by 3.4 times.

The long term portion of debt totals approximately $1,280.0 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

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

4.1.8 Defined Benefit Pension Plan risk

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and OPEB plans (the "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. Benefits are based on each employee's years of service and compensation. The Company initiated 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

APUC manages the assets in its Plans by engaging professional investment managers who operate 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.

4.2 Operational Risk Management

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the generic operational risk of APUC's businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

4.2.1 Risks Inherent to APUC's Businesses

(i) Risk Pertaining to Power Generation

APCo's profitability could be impacted by 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.

APCo's existing long term PPAs and derivative contracts minimize the risk of reductions in average energy pricing across its portfolio of facilities.

(ii) Risks Pertaining to Water Utilities

The water distribution networks of Liberty Utilities 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. Profitability could be impacted by equipment failure at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

These risks are mitigated through the geographic diversification of water distribution operations, and the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. U.S. governmental authorities have the ability to impose restrictions on water usage during drought conditions. If imposed, this could result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(iii) Risks Pertaining to Electric Utilities

The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property. These forest fire risks are mitigated through the use of regular vegetation management and line maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. US governmental authorities have the ability to impose restrictions on electricity usage during periods of power generation disruption and loss of adequate transmission capability. If imposed, this could result in decreased demand for electricity, even if supplies are adequate, which could adversely affect revenues and earnings.

(iv) Risks Pertaining to Gas Utilities

The gas distribution systems owned by Liberty Utilities are subject to significant risks which may lead to fire and/or explosion which may have serious impact on life and property. Risks include third party damage, significant leaks, type/age of pipelines and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Utilities) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining industry standard insurance and the establishment of reserves for expenses.

4.2.2 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 likelihood of being required to incur such costs in the event there is an option or right to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC has recorded a liability of $13.9 million in its financial statements which was assumed in 2014 in conjunction with recent acquisitions.

(i) Generation Group

Generally, the Generation Group's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require the Generation Group to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. The Generation Group has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which the Generation Group has facilities, the Generation Group has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

APUC does not own the property on which the turbines of the St. Leon and the St. Leon II Wind Facilities are located. In 2004, St. Leon entered into long-term right-of-way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by the Generation Group at its option. While the Generation Group anticipates being in a position to renew or extend the existing PPA in 2025, in the event that the Generation Group is unable to renew or extend the agreement, or identify another purchaser of the energy, the Generation Group may choose to decommission the facility. The Generation Group has assessed there to be a remote likelihood of incurring any costs to decommission the wind farm. This also applies to the St. Leon II Wind Facility.

APUC does not own the properties on which the turbines of its U.S. wind facilities are located but have entered into long-term right-of-way agreements with land owners. These agreements have terms ranging between 30-50 years and, upon expiry or termination, require that all facilities, including foundations below grade be removed. While the Generation Group aims to continue operating these facilities indefinitely, there is a certain probability of being required to decommission a facility upon the expiry of its land lease agreement. As such, the Generation Group recorded an asset retirement liability of $11.8 million as at December 31, 2014.

(ii) Distribution Group

Water distribution and wastewater collection and treatment utility systems are operated with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain

in compliance with the applicable regulatory bodies, the Distribution Group has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, and expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus the Distribution Group is allowed to earn a return on its investment.

The Distribution Group operates its electrical distribution facilities with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain in compliance with the applicable regulatory bodies, the Distribution Group has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, and expenses associated with replacing aging electricity distribution facilities and expenses associated with providing new sources of electricity can generally be included in the facility's rate base and thus the Distribution Group is allowed to earn a return on its investment.

The Distribution Group operates its natural gas distribution facilities with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain in compliance with the applicable regulatory bodies, the Distribution Group has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. In addition, the natural gas facilities record asset retirement obligations related to (i) 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, (ii) clean and remove storage tanks containing waste oil and other waste contaminants, and (iii) remove asbestos upon major renovation or demolition of structures and facilities. These maintenance expenses, and expenses associated with replacing aging natural gas distribution facilities and expenses associated with providing new sources of gas can generally be included in the facility's rate base and thus the Distribution Group is allowed to earn a return on its investment. As such, the Distribution Group recorded an asset retirement liability of $2.1 million as at December 31, 2014.

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 Environmental Risks

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

(i) Generation Group

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

The Generation Group's Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric generating facility include possible dam failure which results in upstream or downstream flooding and equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric generating facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, the Generation Group completes frequent formal and informal facility inspections, and on an annual basis, ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3 to 5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the local and migratory bird population, potential harm to the local bat population as well as concerns over noise levels and visual 'harm' to the scenic environment around the wind farm. In order to monitor and mitigate these risks, the Generation Group completes frequent formal and informal facility inspections, and on an annual basis, ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The Generation Group's Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include

potential air emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, the Generation Group maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring equipment. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills, and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, the Generation Group maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

(ii) Distribution Group

The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination.

In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, the Distribution Group maintains ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed EPA and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, the Distribution Group maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet specific standards. The costs of complying with drinking water standards form part of a facility's rate case applications.

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

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, the Distribution Group promptly investigates all reported accidental releases and if applicable, will take all required remedial actions and manage the associated hazardous and universal waste streams in accordance with all applicable Federal and State legislation.

The primary environmental risks associated with the operation of gas distribution systems are related to uncontrolled natural gas release further to significant leaks, equipment damage by construction equipment/third parties or severe weather events and unauthorized discharges to the environment, respectively. The gas distribution assets are heavily regulated by the Pipeline Hazardous Material Safety Administration ("**PHMSA**") under the United States Department of Transportation and their respective State regulations in which the assets are located. Gas distribution systems are subject to detailed annual inspections by the State regulatory agency to ensure strict adherence to applicable regulations. PHMSA reviews company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. The Distribution Group monitors all aspects of pipeline safety and quickly mitigates any identified concerns. Unauthorized gas discharges are reported promptly to the state on discovery, sites are remediated and contaminated soil is disposed in compliance with applicable legislation.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, the Distribution Group promptly investigates all reported accidental releases and if applicable, will take all required remedial actions and manage the associated hazardous and universal waste streams in accordance with all applicable Federal and State legislation.

Prior to their acquisition by the Distribution Group, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("**MGP**") and related facilities. The Distribution Group is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the New Hampshire Department of Environmental Services

("**NHDES**"). The Distribution Group believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental cleanup activities will be $72.6 million which, at discount rates ranging from 2.1% to 3.4%, represents the recorded accrual of $72.3 million as of December 31, 2014. 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, 2014, the Company has reflected a regulatory asset of $102.7 million for the remediation of the MGP and related sites.

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

4.2.5 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.

(i) Generation Group

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

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

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

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

(ii) Distribution Group

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

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

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

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

4.2.6 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.

4.2.7 Specific Environmental Risks

(i) Generation Group

(1) Greenhouse Gas Initiatives

Several north eastern U.S. States have formed a coordination group to develop and implement a multi-state greenhouse gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("**RGGI**"), has received backing from states where APUC operates facilities including Connecticut. RGGI drafted model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program has been implemented to regulate CO_2 emissions from large electrical generation facilities, including the Windsor Locks Thermal Facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks Thermal Facility is the only APUC site that is currently affected by the RGGI regulations. Only the 40 MW gas turbine falls under RGGI as the new 15 MW gas turbine is under the minimum threshold for the RGGI program. As such, APUC needs to purchase allowances only for emissions from the 40 MW turbine, which is expected to operate less than 300 hours per year and generate less than 3,000 tons of CO_2 per year. APUC has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks Thermal Facility to be between U.S. $6.0 thousand and U.S. $12.0 thousand per year.

RGGI has been in effect in Connecticut since 2009. The second compliance period is from January 2012 to December 2014. In 2013, the Windsor Locks Thermal Facility produced 66,008 tons of CO_2, obtained allowances of 54,298 tons through the useful thermal energy set-aside account, and had 21,729 surplus tons rolled over from the first compliance period. As a result, no CO_2 allowances were required to be purchased to comply with RGGI. For 2014, it is estimated that the Windsor Locks Thermal Facility will produce 3,000 tons of CO_2, with 10,019 banked allowances. Therefore, the purchase of allowances is not anticipated. The current price for RGGI allowances is approximately 2 U.S. dollars/ton.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative ("**WCI**"). Each member state/province is now responsible for developing the draft design of a Regional Cap-and-Trade Program and taking the necessary steps to implement the program within its jurisdiction. APUC owns and operates the Sanger Thermal Facility in California and holds investments in two other facilities in Ontario which could be impacted by this program.

On January 2013, the Ontario Ministry of the Environment issued for comments a discussion paper with the key elements of a greenhouse gas reduction program. This discussion paper kicked off a discussion process with key industry sectors and others stakeholders. The Federal government is also moving forward with greenhouse gas ("**GHG**") regulations and it is expected that by 2016 a GHG reduction program will be in place.

The State of California is the first member of the WCI to implement a cap-and-trade program. This program started on January 1, 2012, with the first enforceable compliance obligation beginning with 2013 GHG emissions. Under this program, independent power generation facilities are not eligible for direct/free credits allocations. As such, the Sanger Thermal Facility will have to make provisions to purchase allowances. In 2012, an affiliate of APUC signed an amendment to the PPA for the Sanger Thermal Facility that allows such affiliate to recover all costs for carbon compliance from PG&E through payments for energy. This PPA amendment includes a formula by which PG&E offsets the Sanger Thermal Facility's costs of complying with California's cap-and-trade regime for the years 2013 and through 2015.

On December 15, 2011, Québec announced the adoption of the cap-and-trade system for greenhouse gas emission allowances, which is based on the rules established by the WCI. The link between the Québec and California cap-and-trade programs became effective on January 1, 2014. The WCI is not applicable to any of the present Québec operations of APUC.

The Carbon Disclosure Project ("**CDP**") is an independent non-profit organization that represents institutional investors managing over $87.0 trillion in assets. The CDP is specifically working to encourage companies worldwide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both potential physical impacts and regulatory changes that may result in an effort to address climate change.

APUC has submitted an annual greenhouse gas emissions inventory to the CDP since 2008. In 2012, APUC's GHG's emissions decreased 10% from 2011. The inventory for 2013 was compiled in the second quarter of 2014, and is available. The emissions data includes both direct emissions from APUC's processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations. Results are available on the CDP website.

(ii) Distribution Group

(1) Water & Waste Water Distribution Systems

The LPSCo Water System operates where groundwater pollutants, namely trichloroethylene (" **TCE**") originally discharged into the ground by a former aerospace manufacturing plant in the nearby City of Goodyear, are progressing toward three of the twelve wells that provide water to the Litchfield service area. The EPA began monitoring TCE in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA regular technical meetings in regards to this monitoring program, the LPSCo Water System monitors its wells for this groundwater pollutant through the sampling and testing of water from wells that are potentially at risk of contamination.

To date there have not been any detectable levels of TCE in the water from wells used by the LPSCo Water System. EPA's monitoring and control efforts have begun to show reducing concentrations in monitoring wells associated with the northeastern portion of the plume, closest to the LPSCo Water System wells. Remedial efforts have intensified in the northwestern portion of the plume in order to ensure full capture of the plume. In 2014, remedial efforts continued to demonstrate success with a reduction in the threat of contamination at the LPSCo Water System's nearest three drinking water wells. The costs of such containment measures are being borne by the "responsible party" (Crane Industries). In the event that any wells exceed the EPA permitted TCE level, the LPSCo Water System would undertake the appropriate actions which may include installing appropriate treatment facilities or removing the well from the water distribution system of the utility. In the event that removal of a well is necessary there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the immediate needs of all of the LPSCo Water System's customers, but replacement wells would need to be constructed over time.

In addition, the LPSCo Water System has identified alternate sites where replacement wells can be established to replace this potential lost capacity. The cost of establishing a new well is estimated to be between U.S $2.0 million and U.S. $3.5 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, proximity of newly constructed well to water distribution lines, volume of water available at the new site, and acquisition of land and groundwater rights. The Distribution Group does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2014.

(iii) Natural Gas Distribution Systems

(1) Concord MGP

EnergyNorth Gas System received a notice letter from the NHDES in September 1992. The notice related primarily to contamination identified in the pond adjacent to Interstate 93 in Concord, New Hampshire, although it was broad enough to also include the former Manufactured Gas Product ("**MGP**") site itself.

Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond of Interstate 93 as the New Hampshire Department of Transportation ("**NHDOT**") began site preparation work for the reconfiguration of that interchange. Subsequent investigations by EnergyNorth Gas System and others indicate that contaminants originating from the MGP are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

The site is currently under Phase III Site remediation, where Phase II was completed and approved by NHDES in July 2012. In December 2014, EnergyNorth received the Groundwater Management Permit. In March 2015, EnergyNorth Gas System will submit its Remedial Action.

(2) Dover MGP

In 1999, NHDES sent notice letters to current and former site owners and operators of the Dover, New Hampshire site including Public Service Company of New Hampshire ("**PSNH**") and its parent company, Northeast Utilities (" **NU**"); EnergyNorth Gas System; Northern Utilities, Inc.; and Central Vermont Public Service Company.

The evaluation of the nature and extent of MGP impacts to the site have been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cocheco River. These residuals, which include tars, oils, and purifier waste, have been found in surface soil, subsurface soil, groundwater, and river sediment.

The site is currently under the management of PSNH and in Phase IV site remediation. Since 2002, PSNH has had responsibility for site management and conducted most of the work at the site.

(3) Keene MGP

NHDES first investigated a site adjacent to the former Keene MGP in Keene, New Hampshire in 1986. PSNH, the former owner and operator, and its parent company NU, conducted several site assessments of the former MGP during the early and mid-1990s. PSNH/NU completed a site Investigation in 1996 in response to a notice letter from the NHDES. PSNH/NU has had responsibility for site management and interactions with NHDES since that time. In response to a request from PSNH/NU, NHDES sent a notice letter to EnergyNorth Gas System in April 2001. EnergyNorth Gas System responded to the NHDES on April 27, 2001, indicating that it would continue to coordinate with PSNH and that it was evaluating its potential liability, if any, at the site.

Residual materials from the former MGP have been identified at the site in sediments of the adjacent Mill Creek and Ashuelot River. Removal of impacted sediment areas constituting readily apparent harm and restoration of the creek bed and portions of the river bed is the likely remedial alternative for the aquatic portion of the site.

The site is currently under the management of PSNH and the seven year remediation project was completed in December 2012. PSNH has taken the lead on investigation at this site, and the site is under a Phase IV remediation. In February 2014, EnergyNorth Gas System and PSNH entered into a settlement agreement providing for EnergyNorth Gas System's share of the remediation expense for the Keene MGP site.

(4) Laconia MGP & Liberty Hill Disposal Site

The former MGP was located in Laconia, New Hampshire. In the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford, New Hampshire.

In 1994 and 1995, PSNH one of the former owners and operators of the Laconia MGP, conducted limited site investigations at the plant. In 1996, NHDES sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and NU, and to EnergyNorth Gas System, another former owner. EnergyNorth Gas System and PSNH reached a settlement in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES. EnergyNorth Gas System retained responsibility for any decommissioning-related liabilities, including off-site disposal.

Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River and the site is currently under the lead of PSNH. Residual materials from the former MGP were disposed of and MGP-related constituents have been detected in soil and ground water.

Based on a settlement with PSNH that has previously been reported to NHPUC, EnergyNorth Gas System has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill Road disposal area.

The Liberty Hill Road site is currently under Phase III remediation. A Conceptual Remedial Design Report was approved by NHDES in December 2012. Removal of the impacted materials will be carried over two construction seasons, 2014 and 2015. The first Construction season went well and approximately 65% of the project is complete.

(5) Manchester MGP Site

In March 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites any un-investigated MGP sites in the State. EnergyNorth Gas System received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP located in New Hampshire from NHDES. Investigations conducted in the summer and fall of 2000 confirmed the presence of MGP related contaminants.

Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

Phase III remediation activities are currently underway and a Remedial Action Plan was submitted for NHDES approval in December 2014.

(6) Nashua MGP Site

At the end of 1998, the NHDES sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua MGP located in New Hampshire to the former plant owners/operators - EnergyNorth Gas System and PSNH and NU.

Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

Phase I and Phase II Site Investigations are complete. The site is currently under Phase III site remediation. In June 2014, EnergyNorth Gas System received a Groundwater Management Permit. In March 2015, a Remedial Action Plan will be submitted to NHDES for approval.

4.2.8 Regulatory Risk

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

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

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

(i) Condemnation Expropriation Proceedings

The Distribution Group's 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 just and fair compensation be paid to the Distribution Group and the Distribution Group believes such compensation would reflect fair market value for any assets that are taken. Notwithstanding the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and therefore there is no assurance that the value received for assets taken will be in excess of book value. In 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Mountain Water Company is the water utility in Western Montana serving the municipality of Missoula owned by Park Water Company. Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will be successful in its condemnation efforts. If the city of Missoula is successful in its condemnation efforts, the quantum of compensation to be paid by the city of Missoula for such taking will be subsequently determined by a valuation hearing by the courts. In respect of such potential valuation hearing, expert reports have been prepared by Mountain Water Company which indicate a fair value of Mountain Water Company of between US$116.0 million and US$141.0 million.

4.2.9 Regimes that Could Impact APUC

(i) Generation Group

As a result of certain legislation passed in Québec (Bill C93), APCo has completed the technical assessments of its hydroelectric generating facility dams, and has put in place a plan to address deficiencies and is actively implementing corrective actions.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates three hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the capital costs related to the Québec facilities, as there are fewer facilities in Ontario and they are of newer construction.

(ii) Distribution Group

The State of California has enacted legislation that requires electric load serving entities to procure increasing amounts of renewable energy (33% by the year 2020), which could negatively impact the source of electricity for the CalPeco Electric System. However, it should be noted that any increases in the cost of electricity associated with these changes will be passed on to the ratepayers through the deferred energy balancing account referred to as the ECAC which is reviewed and approved on an annual basis.

4.2.10 Regimes that Could Benefit APUC

The US federal government has committed to implementing a US carbon reduction strategy, and has included revenue from a federal carbon cap-and-trade program in future budget projections. Similarly, the Canadian federal and provincial governments have indicated increased support for Canadian participation in an integrated North American climate change program.

APUC believes that with its existing portfolio of renewable energy and high efficiency cogeneration facilities within the Power Generation business unit is ideally situated to benefit from an improved competitive position within the North American power sector.

In addition, the US federal government is currently debating the implementation of a country-wide Renewable Energy Portfolio Standard. This would increase the market demand for renewable energy and broaden the opportunities for development of renewable energy projects.

In conjunction with the development of cap and trade programs and working to increase the supply of renewable energy, various North American governments are making legislative and regulatory changes to streamline the approvals process for the development of new renewable energy projects.

4.2.11 Obligations to Serve

(i) Generation Group

The Generation Group is not subject to obligations to serve.

(ii) Distribution Group

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

4.3 Regulatory Climate and Permitting Risks

Profitability of APUC's businesses is in part dependent on regulatory climates in the jurisdictions in which it operates.

The Generation Group

In the case of some APCo hydroelectric generating facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue. The failure to obtain all necessary licenses or permits, including renewals thereof or modifications thereto, may adversely affect cash generated from operating activities.

In the United States, FERC issues licenses for the construction, operation and maintenance of hydroelectric generating facilities. Hydroelectric generating facilities are required to be licensed or have valid exemptions from FERC. Failure to maintain such licenses, including amendments or modifications thereto, may result in the owner being unable to operate the licensed facility and could adversely affect cash generated from operating activities.

There are two different mechanisms by which APCo's generating facilities sell power. They either sell power to a utility under a PPA, wherein the price is tied to the market or to the Avoided Cost, or they sell power directly into the market at market-based rates. As noted in Section 3.1.1(ii), the Generation Group's generators are either self-certified as a QF or as a EWG. Each generator sells power from its project in up to three ways: (1) If the facility is a QF, it may sell power at a rate that equals the utility purchaser's Avoided Costs or at a negotiated or market-based or tariff rate; (2) If the facility is an EWG or a QF with a capacity greater than 20 MW with MBR Authority, it may sell its power at a rate that equals a market-based rate or a rate negotiated between a buyer or seller. In order to sell power at a rate equal to the utility's Avoided Cost, the facility must maintain QF status; (3) Absent QF status, in order to maintain authority to sell power, it must either sell at market-based rates, or make sales at cost-based rates as a regulated utility. If a facility loses EWG status, it will be regulated as a public utility and not afforded certain waivers of PUHCA and FERC's regulations otherwise applicable to EWGs

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

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

Condemnation Expropriation Proceedings

The Distribution Group's electricity and natural gas distribution systems could be subject to condemnation expropriation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to the Distribution Group, and while the Distribution Group believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value. In 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The water utility in Western Montana serving the municipality of Missoula is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude, whether the city of Missoula will be successful in its condemnation efforts and, if successful, the amount of compensation to be paid to APUC.

4.4 Safety Considerations

The operation of the facilities require adherence to safety standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and administrative sanctions. To mitigate the risk of administrative sanctions and to minimize safety risks to employees and contractors, APUC works continuously with all employees to ensure the development and implementation of a progressive, proactive safety culture within all operations. APUC has multiple active safety committees operating with each operating unit and has a dedicated staff to ensure that the existing safety program is continuously improving.

4.5 Labour Relations

While labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment without disruptions cannot be assured.

Generation Group

With the exception of the Tinker Hydro Facility, employees of APCo and their material subcontractors are non-unionized. The Tinker Hydro Facility is unionized with 5 employees belonging to International Brotherhood of Electrical Workers ("**IBEW**") and the current collective bargaining agreement expires December 31, 2015.

Distribution Group

In California, 58 employees at the CalPeco Electric System are unionized. The current collective bargaining agreement with the IBEW was renegotiated in August 2014 for a term of three years, until August 2017. The CalPeco Electric System has good relations with the IBEW union.

In Missouri, there is one union contract with the IBEW covering 43 employees at the Midstates Gas System. The current collective bargaining agreement with the IBEW was renegotiated in June 2013 for a four year term expiring in June 2017. The Midstates Gas System has good relations with the IBEW union.

In New Hampshire, there are currently four union contracts. The United Steelworkers of America (" **Steelworkers**") represent approximately 94 employees working in field operations in the gas distribution business and their contract will expire in April 2016. In the electric business there are two IBEW locals representing approximately 34 field employees. The contracts for these groups will expire in May 2014. There are also 2 engineers in the Utility Workers Union of America ("**UWUA**") and their contract will expire in May 2017. The Steelworkers recently organized the Customer Service representatives, currently with 27 members. The contract for this group expires February 2017.

In Massachusetts, the UWUA currently represents 67 gas operations employees. There is a two year extended contract in effect which will expire on April 30, 2015. The UWUA recently organized the Customer Service representatives. There are 8 employees in this group. Negotiations for a first contract will begin shortly.

All employees at the water and wastewater systems in Arizona, Arkansas, and Texas are non-union.

All employees at the natural gas systems in Georgia, Illinois, Iowa and Missouri are non-union.

4.6 Dependence Upon Key Customers

(i) Generation Group

The customers of the Generation Group's facilities are primarily large utilities. See the summaries of the contracts in Schedules A and B. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, cash flow available to shareholders of APUC would decline.

(ii) Distribution Group

The customers of the Distribution Group are primarily residential. Large commercial and industrial customers make up less than 20% of gross revenues, with no single customer accounting for a significant portion of gross revenues. As such, the Distribution Group is not dependent upon a few key customers.

4.7 Potential Conflicts of Interest

On December 21, 2009, an agreement was reached to internalize management. Since then, management of APUC has been conducted by officers of APUC. In addition, most other business associations between APUC and the Senior Executives have been resolved. See "*Description of the Business - Business Associations with APMI and Senior Executives*" While there may be situations in which conflicts of interest arise between the Senior Executives and APUC in relation to the interests of APUC, APUC has policies in place to deal with potential conflicts of interest.

4.8 Construction / Development Risk

The Generation Group actively engages in the development and construction of new power generation facilities. The current pipeline of projects either currently in construction or in development is $1.2 billion and is mainly renewable solar and wind projects. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. Examples of inherent risks pertaining to power generation facility development can include: technical issues with the interconnection utility, unfavorable permitting results or delays emanating from State, Provincial or Federal agency interface, construction delays or cost overruns, currency fluctuations affecting the cost of major capital components such as turbines, equipment performance outside of expectations, and land owner disputes. The Generation Group mitigates these risks through its due diligence processes, sound project management principals and appropriate contingency plans and reserves.

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

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

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

4.9 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. 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 have developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes ensure an 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 Generation and Distribution Groups ' senior management 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 Generation and Distribution Groups .

5. DIVIDENDS

Common Shares

The total amount of dividends declared on the Common Shares for fiscal 2012, 2013 and 2014 were $50.2 million, $68.3 million, and $82.9 million, respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2012, 2013 and 2014 were $0.30, $0.33 and $0.37, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective August 14, 2014, APUC's Board of Directors approved a dividend increase from CDN $0.34 to U.S. $0.35, paid quarterly at a rate of U.S. $0.0875 per common share. The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. APUC's consolidated assets are approximately 82% based in the U.S. and generate approximately 77% of its underlying cash flows

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 "*Risk Factors*".

Preferred Shares

On November 9, 2012, APUC issued 4,800,000 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 2012, 2013 and 2014, dividends paid to Series A Share holders totalled $0.8 million, $5.4 million, and $5.4 million.

On January 1, 2013, the Corporation issued 100 redeemable Series C preferred 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 preferred shares provide dividends essentially identical to that expected from the Class B units. In 2013 and 2014, dividends paid to Series C preferred shareholders totalled $0.9 million and $0.9 million.

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, dividends paid to Series D Shareholders totalled $4.1 million.

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, 2014, 63,839,443 Common Shares had been registered with the Reinvestment Plan.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 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 Common 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 Common Shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

As at December 31, 2014, APUC had 238,149,468 issued and outstanding Common Shares and, as at March 30, 2015, APUC had 238,879,068 issued and outstanding Common Shares.

6.2 Private Placements of Subscription Receipts and Common Shares to Emera

As at March 30, 2015, in total Emera owns 50,126,766 Common Shares, representing approximately 21.0% of the outstanding Common Shares of APUC. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

Subscription Receipts

On October 7, 2014, the Company issued 8,708,170 Subscription Receipts of APUC at a purchase price of $8.90 per Subscription Receipt for an aggregate subscription price of $77.5 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Odell Wind Project in Minnesota (the "**Odell Acquisition**"). The proceeds of the subscription are intended to be used by APUC to partially finance the Odell Acquisition and the completion of the Odell Wind Project. Subject to adjustments as provided in the applicable subscription

agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on November 14, 2015 (the first anniversary of the closing of the Odell Acquisition) or the commercial operation date of the Odell Wind Project, whichever is first to occur.

On December 2, 2014, the Corporation issued 3,316,583 subscription receipts of APUC to Emera at a purchase price of $9.95 per subscription receipt for an aggregate subscription price of $33.0 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Park Water Company in Montana (the "**Park Water Acquisition**"). The proceeds of the subscription are intended to be used by APUC to partially finance the Park Water Acquisition. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on December 29, 2015 (the first anniversary of the closing of the subscription transaction) or the closing of the Park Water Acquisition, whichever is first to occur.

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

Common Shares

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

For the year ended December 31, 2013, APUC issued a total of 15,223,016 Common Shares for proceeds of $90.5 million pursuant to the conversion of subscription receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- In connection with the closing of the acquisition of the Minonk and Senate Wind Facilities that occurred on December 10, 2012, on February 7, 2013, APUC issued 2,614,005 Common Shares upon the conversion of subscription receipts that were issued at a price of $5.74 per subscription receipt. Additionally, on February 14, 2013, APUC issued 5,228,011 Common Shares upon the conversion of subscription receipts that were issued at a price of $5.74 per subscription receipt. The total $45.0 million in cash proceeds were used to fund a portion of the cost of the acquisition;
- On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in CalPeco Electric System, APUC received $38.7 million from Emera related to the issuance of 8,211,000 subscription receipts which were issued at a price of $4.72 per subscription receipt. On February 14, 2013, APUC issued 3,421,000 Common Shares upon partial conversion of these subscription receipts; and
- On March 26, 2013, in connection with the acquisition of the Peach State Gas System, APUC issued 3,960,000 Common Shares at a price of $7.40 per share to Emera for total proceeds of approximately $29.3 million.

For the year ended December 31, 2012, APUC issued a total of 26,380,750 Common Shares for proceeds of $142.6 million pursuant to the conversion of subscription receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- On May 14, 2012, in connection with the acquisition of Granite State Electric System and EnergyNorth Gas System, APUC issued 12,000,000 Common Shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions;
- On June 29, 2012, in connection with the acquisition of Sandy Ridge Wind Facility, APUC received $15.0 million relating to 2,614,006 subscription receipts issued at a price of $5.74 per share and issued the Common Shares related to these subscription receipts on July 13, 2012;
- On July 31, 2012, in connection with the acquisition of the Midwest Gas System, APUC issued 6,976,744 Common Shares upon conversion of the same number of subscription receipts, which were issued to Emera at a price of $6.45 per subscription receipt. The $45.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the Midwest Gas System acquisition; and
- On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in CalPeco Electric System, APUC received $38.8 million from Emera related to the issuance of 8,211,000 subscription receipts which were issued at a price of $4.72 per subscription receipt. On December 27, 2012, APUC issued 4,790,000 Common Shares upon partial conversion of these subscription receipts.

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.

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 Portfolios 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 preferred shares to the holders of the Class B units of St. Leon LP, in exchange for such Class B units. (See "Description of the Business – Business Associations with APMI and Senior Executives - St Leon LP 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, 2014, 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 Series 2A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $59,967,000 principal amount of Series 2A Debentures.

On January 20, 2012, APUC provided the holders of its Series 2A Debentures notice of its intention to redeem for equity, effective on the Series 2A Redemption Date (February 24, 2012), all of the issued and outstanding Series 2A Debentures. Prior to the Series 2A Redemption Date, $2,916,000 principal amount of Series 2A Debentures were converted by debenture holders into 485,998 Common Shares.

On the Series 2A Redemption Date, APUC issued and delivered 9,836,520 Common Shares to the remaining holders of Series 2A Debentures, representing the number of freely tradable Common Shares obtained by dividing the aggregate principal amount of debentures of $57,041,000, by 95% of the current market price of the Common Shares on the Series 2A Redemption Date.

As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

6.4.2 Series 3 Debentures

On December 2, 2009, APUC issued $63,250,000 principal amount of Series 3 Debentures.

On November 19, 2012, APUC announced its intent to redeem on the Series 3 Redemption Date (January 1, 2013) all of the outstanding Series 3 Debentures at such date. During the year ended December 31, 2012, a principal amount of $61.6 million Series 3 Debentures were converted into 14,669,266 Common Shares. The Series 3 Debentures were convertible into Common Shares of APUC at the option of the holder at a conversion price of $4.20 per common share. On December 31, 2012, there was $0.96 million principal amount of Series 3 Debentures outstanding. On January 1, 2013, APUC redeemed the outstanding Series 3 Debentures and issued 150,816 Common Shares as a result of the redemption. Following the redemption, there were no Series 3 Debentures outstanding.

6.5 Employee Share Purchase Plan

APUC has an employee share purchase plan ("**ESPP**") in place that provides eligible employees the opportunity to have a portion of their earnings withheld to be used 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. Shares purchased through the APUC matched portion vest over a one year period. 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. For the year ended December 31, 2014, APUC issued 93,598 shares under the ESPP and recorded $0.1 million in compensation expense.

As at December 31, 2014, a total of 240,411 shares had been issued under the ESPP.

6.6 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 Deferred Share Units ("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 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 the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. For the year ended December 31, 2014, APUC issued 35,455 DSUs under the Deferred Share Unit Plan.

As at December 31, 2014, 110,241 (2013 – 74,786) DSUs were outstanding pursuant to the election of the Directors to defer a percentage of their 2014 and 2013 Director's fee in the form of DSUs.

6.7 Performance Share Units

APUC issues performance share units ("**PSU**") to certain members of management as part of APUC's long-term incentive program.

The PSUs have a three year vesting period, after which the number of shares vested can range from 0% to 184% of the number of PSUs granted. Dividends accumulate during vesting periods are converted to PSUs based on the market value of the shares on that date. None of the 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 APUC. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards.

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 year, the Company issued 407,962 PSUs to executives and employees of the Company.

As at December 31, 2014, a total of 440,086 PSU's have been 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 was approved by shareholders at the annual and special meeting of shareholders of APUC held in 2013.

Until the occurrence of certain specific events, the rights will trade with the Common Shares of APUC 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, with the exception of Emera, 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 60 days. If at the end of 60 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 April 23, 2013, the shareholders of APUC approved an amendment to and the continuance of the Rights Plan. In the Amended and Restated Rights Plan, the definition of "Exempt Acquisition" has been amended to provide that, in determining whether Emera has become a beneficial owner of more than 25% of the Common Shares outstanding as a result of certain issuances of Common Shares or convertible securities by the Corporation (including a distribution of Common Shares or convertible securities by way of private placement), the Common Shares to be issued to Emera shall be included in the aggregate number of outstanding Common Shares. If, under such determination, Emera becomes the beneficial owner of not more than 25% of the outstanding Common Shares as a result of an Exempt Acquisition, Emera is not considered an "Acquiring Person" for purposes of the Amended and Restated Rights Plan. The Amended and Restated Rights Plan otherwise provides that the Common Shares to be issued to a person (other than Emera) under an Exempt Acquisition are not to be included in the outstanding Common Shares in determining whether such person becomes the beneficial owner of more than 25% of the outstanding Common Shares.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2016 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 share options, to acquire a proprietary interest in the Corporation.

The Stock Option Plan authorizes the Board to issue stock options (" **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 10% of the number of Common Shares outstanding at the time the Options are granted. 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 10% 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.

During the year, the Company issued 969,998 options to employees of the Company.

As at December 31, 2014, a total of 5,537,127 options had been issued and outstanding under the plan, which is 2.3% of the total outstanding Common Shares of the Corporation. The number of Common Shares that have been issued pursuant to the Stock Option Plan is nil.

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 under the symbol "AQN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares for the periods indicated (as quoted by the TSX).

2014	High ($)	Low ($)	Volume (000's)
January	7.43	7.04	9,079,681
February	7.45	7.08	4,992,128
March	7.98	7.11	9,409,715
April	7.95	7.51	4,102,203
May	8.25	7.82	8,473,848
June	8.28	7.99	6,788,599
July	8.25	7.96	5,871,277
August	9.10	8.06	5,167,304
September	9.13	8.72	11,625,161
October	9.28	8.20	8,218,777
November	9.83	9.10	9,103,536
December	10.25	9.23	12,433,307

7.1.2 Preferred Shares

Series A Shares

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

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).

2014	High ($)	Low ($)	Volume (000's)
January	22.06	20.65	109,144
February	22.99	21.32	111,497
March	22.43	21.77	243,566
April	22.81	21.92	99,216
May	23.28	22.31	61,124
June	22.72	21.69	74,009
July	22.86	22.07	266,535
August	23.60	22.50	90,346
September	23.91	22.82	53,421
October	23.86	23.40	204,829
November	24.73	23.62	39,006
December	24.41	23.25	71,594

Series D Shares

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

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series D Shares for the periods indicated (as quoted by the TSX).

2014	High ($)	Low ($)	Volume (000's)
March 5-31	24.64	23.91	549,456
April	24.72	24.20	242,314
May	24.95	24.48	131,085
June	24.95	24.45	105,384
July	25.00	24.51	93,015
August	25.35	24.76	261,402
September	25.99	24.95	128,989
October	26.30	25.04	239,602
November	25.85	25.29	25,908
December	26.01	25.00	52,525

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.

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. During the year ended December 31, 2014, no options were exercised. As at December 31, 2014, APUC had 5,537,127 options issued and outstanding. As at December 31, 2014, 3,601,647 options were exercisable. No options were exercised in 2014 or 2013 or 2012.

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term
Balance at January 1, 2014	4,567,129	$5.70	5.45
Granted	969,998	$7.95	8.00
Balance at December 31, 2014	5,537,127	$6.09	4.96
Exercisable at December 31, 2014	3,601,647	$5.33	4.20

In addition, APUC issued Common Shares to Emera upon the conversion of subscription receipts in 2012 and 2013 and issued Common Shares to Emera upon a private placement in March 2013 as described under "*Description of Capital Structure – Private Placements of Subscription Receipts and Common Shares to Emera*".

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

The following securities of APUC are subject to contractual restrictions on transfer as of the date of this AIF:

Description	Number of Securities subject to contractual restrictions	Percentage of class
Common Shares	50,126,766	21.0%

Holdings of Common Shares by Emera greater than 15% and up to 25% of the outstanding Common Shares are subject to a limited restriction on transfer and certain voting covenants contained in the Strategic Investment Agreement.

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 Toronto, Ontario, Canada Age: 64	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. Trustee of APCo since October 22, 2002
LINDA BEAIRSTO Oakville, Ontario, Canada Age: 54	Ms. Beairsto has been Chief General Counsel and Corporate Secretary for APUC since June 2011. Previously, 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., Executive Vice-President & 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. In 2013, Ms. Beairsto completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Officer of APUC since June 6, 2011
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 55	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. Officer of APCo since September 17, 2007
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 57	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. Trustee of APCo since July 27, 2009
CHRISTOPHER K. JARRATT Oakville, Ontario, Canada Age: 56	Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc., 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.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
KENNETH MOORE Toronto, Ontario, Canada Age: 56	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. Trustee of APCo since December 18, 1998
DAVID PASIEKA Oakville, Ontario, Canada Age: 58	David Pasieka is the President of APUC's Distribution Business Group. As President, 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.	President - Liberty Utilities (Canada) Corp. since September 1, 2011
IAN E. ROBERTSON Oakville, Ontario, Canada Age: 55	Ian Robertson is the Chief Executive Officer of the Corporation. Mr. Robertson is a founder and principal of Algonquin Power Corporation Inc., 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) 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.
MASHEED SAIDI Dana Point, California, United States Age: 60	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 US Transmission for National Grid USA, for which she was responsible for all aspects of US transmission business. Ms. Saidi previously served on the Board of Directors on the Northeast Energy and Commerce Association. She serves as Chairman of the Board of Directors for the non-profit organization Mary's Shelter. 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 Las Vegas, Nevada, United States Age: 59	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

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
MIKE SNOW Markham, Ontario, Canada Age: 54	Mike Snow is the President of APUC's Generation Business Group and is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mr. Snow 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 Richard Ivey School of Business – University of Western Ontario.	Officer of APUC since July 4, 2011
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 65	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. Trustee of APCo since September 8, 1997
GEORGE TRISIC Oakville, Ontario, Canada Age: 54	George Trisic is the Senior Vice President of Business Services 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.	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 March 30, 2015, the directors and executive officers of Algonquin, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 987,442 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 Algonquin 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 comprised of three directors of APUC, Mr. Ball (Chairman), Mr. Moore 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 APUC's audit committee (the "**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, Inc. 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.

KPMG LLP was the external auditor of APUC until March 22, 2013, when Ernst & Young LLP's appointment as external auditor of APUC became effective. For the financial year ended December 31, 2014 and December 31, 2013, Ernst & Young LLP and KPMG LLP charged the following fees to APUC respectively:

Services	2014 Fees ($)	2013 Fees ($) (KPMG LLP)[5]	2013 Fees ($) (Ernst & Young LLP)[6]	2013 Total Fees
Audit Fees[1]	1,965,600	351,000	1,242,000	1,593,000
Audit-Related Fees[2]	293,858	—	40,806	40,806
Tax Compliance Fees[3]	—	86,575	—	86,575
Other Tax Fees[4]	101,605	141,722	40,000	181,722
All Other Fees	28,000	61,100	—	61,100

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.

5 For the period from January 1, 2013 to March 22, 2013, when KPMG LLP's resignation as auditor of APUC became effective. KPMG LLP provided additional tax services to APUC after KPMG LLP ceased to be the external auditor for APUC. The fees for such services are not included in the above table.

6 For the period commencing March 22, 2013, when Ernst & Young LLP's appointment as external auditor of APUC became effective, until December 31, 2013.

8.3 Corporate Governance and Compensation Committees

The directors have also established a Corporate Governance Committee (" **CGC**") comprised of four of the directors of APUC, Mr. Steeves (Chair), Mr. Huskilson Ms. Saidi, and Mr. Moore. The CGC typically includes two members of management by invitation, Mr. Robertson and Mr. Jarratt.

The directors have also put in place a Compensation Committee (" **CC**"), comprised of three directors of APUC, Mr. Huskilson (Chair), Mr. Ball, and Ms. Saidi. The CC typically includes two members of management by invitation, Mr. Robertson and Mr. Jarratt.

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 Co., 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 management's discussion and analysis for the fiscal year ended December 31, 2014, 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 is a major shareholder of APUC. Emera has a strategic relationship with APUC, see "*Material Contracts*". 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 2014 are as follows:

(i) Trafalgar proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "**Trafalgar Hydro Facilities**"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain subsidiary entities of APUC, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that APUC was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against APUC were dismissed by summary judgment. On October 22, 2009, Trafalgar filed an appeal from the November 6, 2008 summary judgment to the United States Court of Appeals for the Second Circuit. As discussed further below, as the proceedings continued, the United States Second Circuit Court of Appeals, among other things, (i) on November 2, 2010 dismissed the claims against APUC in the civil proceedings; and (ii) on January 30, 2013, held that Algonquin has a security interest in Trafalgar's engineering malpractice claim and its proceeds.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving APUC judgment on its claims. Trafalgar asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied Trafalgar's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of APUC's remedies under the loan documents, including the calculation of the debt and the disposition of collateral. The District Court entered judgment in favor of APUC with regard to the default and APUC's entitlement to recourse to the collateral, but without determining the amount due under the note. The District Court then closed the case.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals, and in the alternative, sought to have the Second Circuit certify a legal question to the New York State Court of Appeals. The Second Circuit denied the petition and certification request which petition was denied on June 17, 2013. On September 16, 2013, Trafalgar filed a Petition for a Writ of Certiorari with the United States Supreme Court. Algonquin filed a brief in opposition to the Petition on October 18, 2013. On December 2, 2013, the United States Supreme Court denied Trafalgar's petition for a Writ of Certiorari. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been denied without prejudice to re-filing the motion after the court determines the amount of Algonquin's claim and the validity of any defenses to the claim. Algonquin and Trafalgar have each filed motions with the Court seeking a determination of those issues. Those motions are under consideration by the Court.

The Court has approved the sale of all seven of the Trafalgar facilities. Of the seven, one has closed while the other six is anticipated to close upon obtaining regulatory approval. The parties are attempting to resolve this matter through good faith settlement negotiations.

(ii) Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (the "**Québec AG**") filed suit in Québec Superior Court against Algonquin Dévelopment (Côte Ste-Catherine) Inc. (Dévelopment Hydromega), a predecessor company to an a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Dévelopment Côte Ste-Catherine Inc. had been paying to St. Lawrence Seaway Management Corporation ("**Seaway Management**") under the water lease relating to the Côte Ste-Catherine hydroelectric generating facility. Algonquin Dévelopment (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011 the Québec Court of Appeal ordered Algonquin Dévelopment (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Dévelopment (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $6.4 million. The parties are attempting to resolve this matter through good faith negotiations.

(iii) Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership (" **Long Sault**") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("**TMC**") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. The Application was heard in May 2014. 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. The OEFC has until April 13, 2015 to appeal this decision.

(iv) Dimos and Katsekas breach of contract claim

On September 30, 2013, Dimos and Katsekas, previous owners of the Clement Dam Hydroelectric, LLC. (" **Clement Dam Hydro Facility**"), filed a demand for arbitration with APFA alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for $1,345,257 for alleged breach of such agreements and $155,821 for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements. An arbitration hearing date is scheduled for May, 2015.

The Royalty Agreement obligations were guaranteed by the Clement Dam Hydro Facility pursuant to a guaranty. On December 14, 2014, Dimos and Katsekas filed a complaint against the Clement Dam Hydro Facility which seeks to enforce certain obligations under a guaranty. In the event the claimants prevail against APFA in the aforementioned arbitration, and APFA does not pay any judgment rendered against it, claimants will pursue their claims against the Clement Dam Hydro Facility. APFA is defending the Clement Dam in this matter pursuant to the sale agreement with the purchaser of the Clement Dam Hydro Facility. At present, the litigation has been stayed pending the outcome of the arbitration proceeding.

(v) Synergics Energy Services, LLC, breach of contract claim

On September 4, 2013, the plaintiff, previous owners of the Great Falls Hydro Facility, filed a complaint for alleged breach of the 2000 purchase and sale agreement and failure to pay a transfer payment thereunder in the event of the sale of the hydro facility. The claim is for $3,000,000 for alleged breach of the 2000 purchase and sale agreement. The case has been settled.

(vi) Conex Energy-Canada, LLC and Conex Energy, Inc. breach of contract claim

On October 31, 2013, the plaintiffs filed a complaint for, among other things, alleged breach of a confidentiality agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar Facility. On March 3, 2014, APUC brought a motion to dismiss the case. The Court has since dismissed the case.

(vii) Bryson School District in Texas Property Taxes Claim

On February 10, 2014, the Generation Group received correspondence from the Bryson School District (the " **School District**") in Texas regarding Senate Wind LLC's property taxes claiming the Senate Wind Facility owes an additional $2.2 million of

property taxes based on an indemnity in the 2010 agreement with the School District. Senate Wind LLC and the District have settled this matter.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2014, 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.

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 management's discussion and analysis as at and for the periods ended December 31, 2014, 2013 and 2012, 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 is CST Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax.

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 2014 (or prior to 2014 in the case of contracts that are still in effect) that are material to APUC:

(a) **U.S. Wind Portfolio:** Amended and Restated Membership Interest Purchase and Sale Agreement ("**MIPSA**") entered into as of December 30, 2011, as amended and restated as of March 8, 2012, June 29, 2012, and October 9, 2012, and as further amended as of December 10, 2012, by and among APFA and Gamesa USA. Pursuant to the foregoing, APFA acquired 60% of WP SponsorCo and, therefore, 60% of the indirect managing interests in the U.S Wind Portfolio Facilities, in 2012. Pursuant to a Supplement and Amendment to the MIPSA, dated November 27, 2013 and further amended March 31, 2014, between APFA and Gamesa USA, APFA purchased the remaining 40% interest in WP SponsorCo from Gamesa USA on March 31, 2014.

(b) **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 from time to time. A First Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of $135,000,000 5.50% senior unsecured debentures due July 25, 2018. The notes are interest only until maturity. The funds were used to repay borrowings as it related to the construction of the St. Leon Wind Facility and to reduce outstanding indebtedness under the APCo Credit Facility. Second Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated December 3, 2012 providing for the issuance of $150,000,000 4.82% senior unsecured debentures due February 15, 2021. Third Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated January 17, 2014 providing for the issuance of $200,000,000 4.65% senior unsecured debentures due February 15, 2022.

(c) **Emera Strategic Investment Agreement:** Strategic Investment Agreement between APUC and Emera dated April 29, 2011 which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Investment Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

(d) **National Grid Transaction Documents:** Two Stock Purchase Agreements each entered into on December 8, 2010 and amended and restated January 21, 2011 between National Grid, as seller, and Liberty Energy Utilities Co. (subsequently merged into Liberty Utilities Co.), as buyer. One agreement is for the purchase of all issued and outstanding shares of Granite State Electric Company (now known as Liberty Utilities (Granite State Electric) Corp.), and the other is for all the issued and outstanding shares of EnergyNorth Natural Gas Inc. (now known as Liberty Utilities (EnergyNorth Natural Gas) Corp.). The obligations of the buyer under each are guaranteed pursuant to a g

uaranty dated as of December 8, 2010 by APUC as guarantor, in favour of National Grid. The interests of buyer in the agreements were transferred to Liberty Energy NH, and the transactions were completed on July 3, 2012.

(e) **APCo Credit Facility:** Fifth amended and restated credit agreement between APCo, APUC, National Bank of Canada as administrative agent and certain financial institutions dated November 16, 2012 providing for a $200 million senior unsecured credit facility with a maturity date of November 16, 2015.

(f) **U.S. Debt Private Placements:** Trust Indenture dated July 2, 2012 between Liberty Utilities Finance GP1 and The Bank of New York Mellon providing for the issuance of senior unsecured debentures. First Supplemental Indenture dated July 2, 2012 between Liberty Utilities Finance GP1, Liberty Utilities Co. and The Bank of New York Mellon in connection with a U.S. $225 million private placement of senior notes maturing between July 31, 2017 and July 30, 2027. Second Supplemental Indenture dated March 14, 2013 between Liberty Utilities Finance GP1, Liberty Utilities Co. and The Bank of New York Mellon in connection with a U.S. $15 million private placement of senior notes due March 13, 2023. Third Supplemental Indenture dated July 31, 2013 between Liberty Utilities Finance GP1, Liberty Utilities Co. and The Bank of New York Mellon in connection with a U.S. $225 million private placement of senior notes maturing between July 31, 2020 and July 31, 2028.

(g) **Underwriting Agreement:** Underwriting Agreement between APUC and CIBC World Markets Inc. and TD Securities Inc., as Joint Bookrunners, dated February 25, 2014, providing for issuance and sale of 4,000,000 cumulative rate reset preferred shares, Series D of APUC at a price of $25.00 per share for an aggregate purchase price of $100,000,000.

(h) **Underwriting Agreement:** Underwriting Agreement between APUC and CIBC World Markets Inc. and TD Securities Inc., as Joint Bookrunners, dated September 8, 2014, providing for issuance and sale of 16,860,000 common shares of APUC at a price of $8.90 per share for an aggregate purchase price of $150,054,000.

(i) **Underwriting Agreement:** Underwriting Agreement between APUC and Scotia Capital Inc. and CIBC World Markets Inc., as Joint Bookrunners, dated December 4, 2014, providing for issuance and sale of 10,055,000 common shares of APUC at a price of $9.95 per share for an aggregate purchase price of $100,047,250.

(j) **Western Water Acquisition:** Plan and Agreement of Merger, among Liberty Utilities Co., Liberty WWH, Inc., and Western Water Holdings, LLC, dated as of September 19, 2014, providing for the acquisition by Liberty Utilities Co. (by merger of Liberty WWH, Inc. with and into Western Water Holdings, LLC) of Western Water Holdings, LLC and, indirectly, its subsidiaries Park Water Company, Apple Valley Ranchos Water Co., and Mountain Water Company. The payment obligations of Liberty Utilities Co. and Liberty WWH, Inc. under such merger agreement were guaranteed pursuant to a Guaranty, dated as of September 19, 2014, by Algonquin Power & Utilities Corp. in favor of Western Water Holdings, LLC and, following the consummation of such merger, the equity holders of Western Water Holdings, LLC immediately prior to such merger. Consummation of the merger remains subject to satisfaction of the conditions thereto set forth in the foregoing Plan and Agreement of Merger. For further discussion please see "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group*".

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 management discussion and analysis for the year ended December 31, 2014.

SCHEDULE A

Renewable - Hydroelectric, Solar and Wind Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	PPA Expiry Year
Hydroelectric - Ontario Facilities					
Facility: Long Sault Rapids Hydro Facility **Owner**: Algonquin Power (Long Sault) Partnership and N-R Power Partnership	18,000	Abitibi River near Cochrane, Ontario	**Electricity Purchaser:** OEFC **Rates:** $0.0957/kW-hr (average estimate)	111,600	2047
Facility: Hurdman Dam Hydro Facility **Owner**: Algonquin Power Fund (Canada) Inc.	570	Mattawa River near Mattawa, Ontario	**Electricity Purchaser:** IESO (formerly, the Ontario Power Authority) **Rates**: $0.08725/kW-hr Paid on Hydroelectric Contract Incentive rate	3,150	2031
Facility: Campbellford Hydro Facility **Owner**: Algonquin Power (Campbellford) Limited Partnership	4,000	Trent River near Campbellford, Ontario	**Electricity Purchaser:** OEFC **Rates**: $0.0435/kW-hr (average estimate)	26,250	2019
Hydroelectric – Québec Facilities					
Facility: Saint-Alban Hydro Facility **Owner**: Nominee owner is SNC Lavalin Inc., beneficial owner is Algonquin Power Fund (Canada) Inc.	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.0857/kW-hr	37,650	2016
Facility: Glenford Hydro Facility **Owner**: Société en Commandite Chute Ford	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.0857/kW-hr	24,000	2020

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	PPA Expiry Year
Facility: Rawdon Hydro Facility **Owner**: Algonquin Power Fund (Canada) Inc.	2,500	Ouareau River near the Village of Rawdon, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.0832/kW-hr (Jan-May)	15,200	2014 PPA renewal option has been exercised to extend PPA to 2034[6]
Facility: Côte Ste-Catherine Hydro Facility **Owner**: Algonquin Power (Mont-Laurier) Limited Partnership	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: Phase I Energy $0.05700/kW-hr	Phase 1: 13,800	Phase 1: 2020
			Phase II Energy $0.07309/kW-hr Capacity $179.37/kW*	Phase II: 35,100	Phase II: 2018 PPA has renewal option to 2043
			Phase III Energy $0.0761/kW-hr Capacity $188.08/kW* * calculated over the average kilowatt output over the period December to March	Phase III: 34,750	Phase III: 2020 PPA has renewal option to 2045
Facility: Ste-Raphaël Hydro Facility **Owner**: Algonquin Power Fund (Canada) Inc.	3,500	Rivière de Sud near Québec City, Québec	**Electricity Purchaser**: Hydro-Québec **Rates**: $0.0832/kW-hr (Jan - Feb)	21,650	2014 PPA renewal option has been exercised to extend PPA to 2034[6]
Facility: Mont Laurier Hydro Facility **Owner**: Algonquin Power (Mont-Laurier) Limited Partnership	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.06231/kW-hr	20,100	2027
Facility : Rivière-du-Loup Hydro Facility **Owner**: Algonquin Power Fund (Canada) Inc.	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.0857/kW-hr	17,250	2015 PPA has renewal option to 2035

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	PPA Expiry Year
Facility: Hydraska Hydro Facility **Owner**: Algonquin Power Trust	2,250	Yamaska River near the Town of St.-Hyacinthe, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: Jan - May: Summer Energy $0.070/kW-hr Winter Energy $0.1283/kW-hr	9,100	2014 PPA renewal option has been exercised to extend PPA to 2034[6]
Facility: Ste-Brigitte Hydro Facility Owner: Algonquin Power Fund (Canada) Inc.	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.0832/kW-hr (Jan-Feb) [11]	12,550	2014 PPA renewal option has been exercised to extend PPA to 2034[6]
Facility: Belleterre Hydro Facility **Owner**: Algonquin Power Fund (Canada) Inc.	2,200	Winneway River in the Municipality of Laforce, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: Energy $0.0693/kWh Capacity $171.35/kW	11,150	2013 PPA renewal option has been exercised to extend PPA to 2033 [9]
Facility: Donnacona Hydro Facility **Owner**: Société Hydro-Donnacona, S.E.N.C.	4,800	Jacques Cartier River near Donnacona, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.0857/kW-hr	4	2022 PPA has renewal option to 2047
Facility: Arthurville Hydro Facility **Owner**: Algonquin Power Trust	650	Rivière du Sud downstream from Ste-Raphaël	**Electricity Purchaser:** Hydro-Québec **Rates**: No target rate as the site is expected to be offline	0[4]	2013 PPA renewal option has been exercised to extend PPA to 2033[9]
Hydroelectric - New York Facilities					
Facility: Ogdensburg Hydro Facility **Owner**: Trafalgar [2,8]	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.0400/kW-hr (est)[3]	11,100	2016
Facility: Forestport Hydro Facility **Owner**: Trafalgar [2,8]	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.0400/kW-hr (est) [3]	10,900	2016

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	PPA Expiry Year
Facility: Herkimer Hydro Facility **Owner**: Trafalgar [2,8]	1,680	West Canada Creek near Herkimer, New York	**Electricity Purchaser:** National Grid **Rates**: No target rate as the site is expected to be offline	0[4]	2016
Facility: Christine Falls Hydro Facility **Owner**: Christine Falls Corporation[2,8]	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates**: US $0.0400/kW-hr (est)[3]	3,300	2028
Facility: Cranberry Lake Hydro Facility **Owner**: Trafalgar [2,8]	500	Oswegatchie River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates**: No target rate as the site is expected to be offline	0[4]	2016
Facility: Kayuta Lake Hydro Facility **Owner**: Trafalgar [2,8]	400	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates**: No target rate as the site is expected to be offline	0[4]	2028
Hydroelectric - Western Canada Facility					
Facility: Dickson Dam Hydro Facility **Owner:** Algonquin Power Operating Trust	15,000	Innisfail, Alberta	**Electricity Purchaser:** AESO & Capital Power **Rates**: $0.0608/kwh blend of AESO Market rate and CP hedge	65,000	2016[7]
Hydroelectric - Maritime Facilities					
Facility: Tinker Hydro Facility **Owner**: Algonquin Tinker Gen Co.	36,800	Perth-Andover, New Brunswick	**Electricity Purchaser:** AES Town of Perth-Andover **Rates:** AES ~ U.S. $0.0418/kWhr Town of Perth Andover: ~ CDN $0.0835/kWhr	142,000	Perth-Andover Contract through 2021
Facility: Caribou Hydro Facility **Owner:** Algonquin Northern Maine Gen Co.	900	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Energy – ~U.S. $0.0418/kWhr	1,300	n/a

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	PPA Expiry Year
Facility: Squa Pan Hydro Facility **Owner**: Algonquin Northern Maine Gen Co.	1,200	Squa Pan Lake, near Caribou Maine	**Electricity Purchaser:** AES **Rates:** Energy – ~U.S. $0.0418/kWhr	700	n/a
Solar Facilities					
Facility: Cornwall Solar Facility **Owner**: Cornwall Solar Inc.	10,000	Cornwall, Ontario	**Electricity Purchaser:** IESO (formerly, the Ontario Power Authority) **Rates:** $0.443/kWh	14,800	2034
Facility: Bakersfield Solar Facility **Owner**: Algonquin SKIC20 Solar, LLC	20,000	Kern County, California	**Electricity Purchaser:** PG&E **Rates:** $0.883/kWh	46,900	2035
Facility: Bakersfield II Solar Facility **Owner**: Algonquin SKIC10 Solar, LLC	10,000	Kern County, California	**Electricity Purchaser:** (Under Development - PG&E)	26,000	2036 (20 years after COD)
Wind - Canadian Facilities					
Facility: Morse Wind Facility **Owner**: Algonquin Power Morse LP	25,000	Morse, Saskatchewan	**Electricity Purchaser:** SaskPower **Rates:** $0.1040/kW-hr	79,600 (Budgeted production is based on an April 2015 Commercial Operations Date)	2035 (20 years after COD)
Facility: Red Lily Wind Facility **Owner**: Red Lily Wind Energy Partnership	26,400	Saskatchewan	**Electricity Purchaser:** SaskPower **Rates:** $0.0897/kW-hr	88,400	2036
Facility: St.-Damase Wind Facility **Owner**: Société en Commandité Fleur de Lis Éoliennes Saint-Damase	24,000	Saint-Damase, Québec	**Electricity Purchaser**: Hydro-Quebec **Rates**: $0.0976/kW-hr	76,000	n/a
Facility: St. Leon Wind Facility **Owner**: St. Leon Wind Energy LP	104,000	St. Leon, Manitoba	**Electricity Purchaser**: Manitoba Hydro **Rates**: Manitoba Hydro rates are confidential	372,000	2026 + one 5 year extension

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	PPA Expiry Year
Facility: St. Leon II Wind Facility **Owner**: St. Leon II Wind Energy LP	16,500	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro **Rates**: Manitoba Hydro rates are confidential	58,100	2037
Facility: Amherst Island Wind Facility **Owner**: Windlectric Inc.	75,000	Stella, Ontario	**Electricity Purchaser:** (Under Development - IESO [formerly, the Ontario Power Authority])	247,000	n/a
Facility: Chaplin Wind Facility **Owner**: Windlectric Inc.	177,000	Chaplin, Saskatchewan	**Electricity Purchaser**: (Under Development - SaskPower)	247,000	n/a
Wind - U.S. Facilities					
Facility: Minonk Wind Facility **Owner**: Minonk Wind, LLC	200,000	Minonk, Illinois	**Electricity Purchaser:** PJM North Illinois **Rates:** market rates	674,000	2022 [5]
Facility: Senate Wind Facility **Owner:** Senate Wind, LLC	150,000	Graham, Texas	**Electricity Purchaser:** ERCOT North markets **Rates:** market rates	520,000	2027 [5]
Facility: Sandy Ridge Wind Facility **Owner:** Sandy Ridge Wind, LLC	50,000	Tyrone, Pennsylvania	**Electricity Purchaser:** PJM West **Rates:** market rates	158,300	2022 [5]
Facility: Shady Oaks Wind Facility **Owner:** GSG6, LLC	109,500	Lee County, Illinois	**Electricity Purchaser:** Commonwealth Edison **Rates:** market rates	352,400	2032
Facility: Odell Wind Facility **Owner**: O'Dell Wind Farm, LLC.	200,000	Cottonwood, Jackson, Martin and Watonwan Counties Minnesota	**Electricity Purchaser:** (Under Development - Northern States Power)	822,000	2035 (20 years after COD)
Facility: Val-Éo Wind Facility **Owner**: Éoliennes Belle-Rivière, société en commandite	24,000	Saint-Gédéon, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	66,000	n/a

[1] 2014 PPA rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable PPAs. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project

[2] APUC provides Trafalgar with certain operational services in respect of the Trafalgar facilities.

[3] These rates reflect the estimated Avoided Costs of National Grid.

[4] Scheduled to be offline in 2015. No decision has been made as to the timing of repairing these facilities.

[5] 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”.

[6] APUC has exercised its option to begin discussions with Hydro-Québec to enter new PPA agreements for agreements which expired in 2014. Negotiations are currently underway.

[7] APUC currently has an agreement in place to hedge 75% of the target energy production at the facility. See “Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation – Renewable – Hydroelectric - Principal Markets and Distribution Methods – Material Facilities - Dickson Dam Facility - Power Purchase Agreement”.

[8] These facilities have been Court approved for sale.

[9] APUC has exercised its option to begin discussions with Hydro-Québec to enter new PPA agreements for agreements which expired in 2013. Negotiations are currently underway.

SCHEDULE B

Thermal - Biomass, Cogeneration, and Diesel Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser / 2015 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Lease Expiry Year
Thermal - Biomass Facility						
Facility: Valley Power Facility **Owner**: Valley Power L.P.	12,000	Drayton Valley, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation **Rates**: Energy: $0.0709/kW-hr	35,000[1]	2014	Owned
Thermal - Cogeneration Facilities						
Facility: Sanger Facility **Owner**: Algonquin Power Sanger LLC (California)	56,000	Sanger, California	**Electricity Purchaser:** PG&E	140,900	2021	Owned
			Rates: US$ 0. 056/ kW-hr (estimated average)* * subject to gas price indexing **Capacity** – Approximately $254,800 January-April &November-December Approximately $935,300 May-October			
Facility: Windsor Locks Facility **Owner**: Algonquin Power Windsor Locks LLC	70,000	Windsor Locks, Connecticut	**Electricity Purchaser:** ISO New England Ahlstrom	27,500 89,000	Merchant 2027	2027
			Rates: ISO New England-Market Rates , included hourly energy, forward capacity and forward reserve payments CT Class III REC ~US$0.2/kW-hr Mill/NGC - US$0.071/kW-hr* Capacity $210,000** Steam - DNM/NGC - US$10.31/1000lbs* Capacity $132,000 * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are CPI indexed. Capacity Market and Spot Market – market prices			
Thermal - Diesel Facilities						
Facility: Tinker Thermal Facility **Owner**: Algonquin Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** Not Under Contract **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, 2014 Connections[1]	Rates[2]
Black Mountain Sewer System	Liberty utilities (Black Mountain Sewer) Corp.	Carefree, Arizona	Wastewater	2,214	Pursuant to ACC decision 71865
Gold Canyon Sewer System	Liberty Utilities (Gold Canyon Sewer) Corp.	Gold Canyon Arizona	Wastewater	7,515	Pursuant to ACC decision 69664
Bella Vista Water System	Liberty Utilities (Bella Vista Water) Corp.	Sierra Vista, Arizona	Water Distribution	9,357	Pursuant to ACC decision 72251
Tall Timbers Waste System	Liberty Utilities (Tall Timbers Sewer) Corp.	Tyler, Texas	Wastewater	2,277	Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350
Woodmark Waste System	Liberty Utilities (Woodmark Sewer) Corp.	Tyler, Texas	Wastewater	1,816	Pursuant to TCEQ decision on September 16, 2013
LPSCo Water & Waste System	Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Litchfield, Park, Arizona	Wastewater Water Distribution	21,132 19,007	Pursuant to ACC decision 74437
Fox River Water & Waste System	Liberty Utilities (Fox River Water) LLC	Sheridan, Illinois	Wastewater Water Distribution	219 220	Per customer agreement[3] US $240.08 US $141.61
Timber Creek Water & Waste System	Liberty Utilities (Missouri Water) LLC	DeSoto, Missouri	Wastewater Water Distribution	16 25	Pursuant to MOPSC decision WR-2006-4025
Holiday Hills Water System	Liberty Utilities (Missouri Water) LLC	Branson, Missouri	Water Distribution	485	Per MOPSC Case WR-2006-4025
Ozark Water & Waste System	Liberty Utilities (Missouri Water) LLC	Kimberling City, Missouri	Wastewater Water Distribution	230 255	Pursuant to MOPSC decision WR-2006-4025
Holly Lake Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	Hawkins, Texas	Wastewater Water Distribution	152 1,929	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 Water Distribution	413 684	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 Water Distribution	269 274	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369

Utility	Owner	Location	Type of Utility	December 31, 2014 Connections[1]	Rates[2]
Hill Country Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	New Braunfels, Texas	Wastewater Water Distribution	407 225	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 Water Distribution	2,215 6,800	Pursuant to ACC decision 73996
Northern Sunrise Water System	Liberty Utilities (Northern Sunrise Water) Corp.	Sierra Vista, Arizona	Water Distribution	363	Pursuant to ACC decision 72251
Southern Sunrise Water System	Liberty Utilities (Southern Sunrise Water) Corp.	Sierra Vista, Arizona	Water Distribution	872	Pursuant to ACC decision 72251
Entrada Del Oro Waste System	Liberty Utilities (Entrada Del Oro Sewer) Corp.	Gold Canyon, Arizona	Wastewater	336	Pursuant to decision 68306
Seaside Resort Water & Waste System	Liberty Utilities (Seaside Water) LLC	Galveston, Texas	Water Distribution Wastewater	156 156	Per customer agreement[2] US $166.68 US $165.45
Noel Water System	Liberty Utilities (Missouri Water) LLC	Noel, Missouri	Water Distribution	697	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 Water Distribution	185 550	Pursuant to MOPSC decision WO-2010-0345
Pine Bluff Water System	Liberty Utilities (Pine Bluff Water) Inc.	Pine Bluff, Arkansas	Water Distribution	17,830	Pursuant to APSC decision Docket No. 09-130-U
White Hall Water System	Liberty Utilities (White Hall Water) Corp., and Liberty Utilities (White Hall Sewer) Corp.	White Hall, Arkansas	Wastewater Water Distribution	1,825 1,921	Pursuant to rate agreement with City of White Hall dated May 30, 2014
Total connections				**103,027**	

[1] Inclusive of vacant connections.

[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, 2014 Connections[1]	Rates[2]
CalPeco Electric System	Liberty Utilities (CalPeco Electric) LLC	Lake Tahoe, California	Electricity Distribution	Residential – 42,487 Commercial & Industrial – 5,791	Rates pursuant to CPUC decision 12-11-030
Granite State Electric System	Liberty Utilities (Granite State Electric) Corp	Salem, New Hampshire	Electricity Distribution	Residential – 37,981 Commercial & Industrial – 6,660	Rates pursuant to NHPUC decision DE 13-063
Total Connections				**92,900**	

[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, 2014 Connections[1]	Rates[2]
EnergyNorth Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Manchester, New Hampshire	Natural Gas Distribution	Residential – 82,545 Commercial & Industrial – 9,585	Rates pursuant to NHPUC decision DG 14-180
Peach State Gas System	Liberty Utilities (Peach State Natural Gas) Corp.	Columbus, Gainesville, GA	Natural Gas Distribution	Residential – 53,802 Commercial & Residential – 4,330	Rates pursuant to GPSC Docket #34734 Document #156121
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 – 52,155 Commercial & Industrial – 3,696	Rates pursuant to M.D.P.U 10-114
Midstates Gas System - Illinois	Liberty Energy (Midstates Natural Gas) Corp.	Salem, Virden, Vandalia, Xenia, Metropolis, Illinois	Natural Gas Distribution	Residential – 21,485 Commercial & Industrial – 2,120	Rates pursuant to ICC decision IL-14-0371
Midstates Gas System - Iowa	Liberty Energy (Midstates Natural Gas) Corp.	Keokuk, Iowa	Natural Gas Distribution	Residential – 4,025 Commercial & Industrial – 461	Rates pursuant to IUB decision TF-01-68
Midstates Gas System - Missouri	Liberty Energy (Midstates Natural Gas) Corp.	Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri	Natural Gas Distribution	Residential – 51,149 Commercial & Industrial – 6,746	Rates pursuant to MOPSC decision GR-2014-0152
Total Connections				**292,099**	

[1] Inclusive of vacant 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.

"**3793257**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**AAP LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**AC**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Solar Power Generating Facilities - Production Method".*

"**ACC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**ADEQ**" has the meaning ascribed thereto under *"Description of the Business - Distribution 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 - Principal Markets and Distribution Methods".*

"**AIF**" or "**Annual Information Form**" means this annual information form.

"**AirSource**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**AMBOSA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

"**AP Bakersfield"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships- Subsidiaries".*

"**APC**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**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 - Intercorporate Relationships - Subsidiaries"*.

"**APCo Credit Facility**" has the meaning ascribed thereto under *"Material Contracts".*

"**APEFW**" means Algonquin Power Energy From Waste Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APFA**" means Algonquin Power Fund (America) Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APMI**" means Algonquin Power Management Inc., a corporation in which the Senior Executives have an interest.

"**APOT**" means Algonquin Power Operating Trust. See *"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 - Distribution 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"*.

"**APUC Businesses**" means the two businesses through which APUC primarily conducts its operations: independent power generation and utilities (water, natural gas and electric).

"**Arthurville Hydro Facility**" means the Arthurville hydroelectric generating facility.

"**Atmos**" means ATMOS Energy Corporation. See *"General Development of the Business - Three Year History and Significant Acquisitions- Fiscal 2012 - Distribution Group".*

"**Audit Committee**" has the meaning ascribed thereto under *"Directors and Officers - Audit Committee - Audit Committee Charter".*

"**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. See *"Schedule A - Renewable - Hydroelectric, Solar and Wind Facilities".*

"**Bakersfield Solar Project**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**BCI**" means Brampton Cogeneration Inc. See *"General Development of the Business - Three Year History Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**BCI Thermal Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History Significant Acquisitions - Fiscal 2013 - Generation Group".*

"Belleterre Hydro Facility" means the Belleterre hydroelectric generating facility.

"**Bill C-93**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods".*

"**Blackout Period**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Board**" means the APUC Board of Directors.

"**BRRBA**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments".*

"**Burgess Hydro Facility**" means the Burgess Dam hydroelectric generating facility. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**By-Laws**" has the meaning ascribed thereto under "*Directors and Officers - Name, Occupation and Security Holdings* ".

"**CAISO**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Solar Power Generating Facilities - Principal Markets and Distribution Methods".*

"**CalPeco**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**CalPeco Electric System**" has the meaning ascribed thereto *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Campbellford Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Campbellford LP**" means Algonquin Power (Campbellford) Limited Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*."**CBCA**" means the *Canada Business Corporations Act*.

"**CC**" has the meaning ascribed thereto under *"Directors and Officers - Corporate Governance and Compensation Committees"*.

"**CC&N**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group-Regulatory Regimes - Utility Distribution Systems - Water Distribution and Waste Water Collection Systems"*.

"**CDP**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks"*.

"**CEO**" means Chief Executive Officer.

"**CFO**" has the meaning ascribed thereto under *"Directors and Officers - Name, Occupation and Security Holdings"*.

"**CGC**" has the meaning ascribed thereto under *"Directors and Officers - Corporate Governance and Compensation Committees"*.

"**Chapais**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Other Interests in Energy Related Developments"*.

"**Clarica**" has the meaning ascribed thereto under *"Description of the Business - Hydroelectric Generating Facilities - Material Facilities - Long Sault Hydro Facility"*.

"Clement Dam Hydro Facility" means the Clement Dam hydroelectric generating facility. See *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Dimos and Katsekas breach of contract claim"*.

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

"**COG**" has the meaning ascribed thereto under *"Description of the Business - Distribution 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 - Hydroelectric Generating Facilities - Material Facilities - Long Sault Hydro Facility"*.

"**Cornwall Solar**" means Cornwall Solar Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Côte Ste.-Catherine Hydro Facility**" means the Côte Ste-Catherine hydroelectric generating facility. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**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"*.

"**CR**" has the meaning ascribed thereto under *"Description of the Business - Social or Environmental Policies"*.

"**CRA**" has the meaning ascribed thereto under *"Enterprise Risk Management - Financial Risk Management - Tax Risk and Uncertainty"*.

"CRCE" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group"*.

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

"**DC**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Solar Power Generating Facilities - Production Method".*

"**Dickson Dam Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Distribution Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**Distribution Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**DSU**" has the meaning ascribed thereto under "*Description of Capital Structure - Directors Deferred Share Units* ".

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization.

"**ECAC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments".*

"**EFW Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Business Associations with APMI and Senior Executives"*.

"**Eligible Individual**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Eligible Persons**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Emera**" means Emera Inc.

"**EnergyNorth Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**EPA**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Environmental Risks - Generation Group".*

"**ERCOT**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods"*.

"**ERM**" has the meaning ascribed thereto under *"Enterprise Risk Management".*

"**ESA**" has the meaning ascribed thereto under *"Description of the Business - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**ESPP**" has the meaning ascribed thereto under "*Description of Capital Structure - Employee Share Purchase Plan* ".

"**EUA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods".*

"**EWGs**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**FERC**" has the meaning ascribed thereto under *"Description of the Business - General Development of the Business - Three Year History and Significant Acquisitions - Transmission Group".*

"**FIT**" means Feed-In_Tariff.

"**FPA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**GA**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Long Sault Global Adjustment Claim".*

"**GAF**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Material Facilities".*

"**Gamesa**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**Generation Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Generation Credit Facility**" has the meaning ascribed thereto under "*General Development of the Business - Three Year Historical and Significant Acquisitions - Fiscal 2012*"

"**GHG**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Generation Group".*

"**Gold Canyon Water System**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**Goldwind**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group ".*

"**gpd**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**GRAM**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Material Facilities".*

"**Granite State Electric System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**GRI**" has the meaning ascribed thereto under "*Description of the Business - Social or Environmental Policies"* .

"**GW**" means a gigawatt.

"**Hurdman Hydro Facility**" means the Hurdman hydroelectric generating facility.

"**Hydraska Hydro Facility**" means the Hydraska hydroelectric generating facility.

"**Hydro Quebec**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

"**IBEW**" has the meaning ascribed thereto under *"Enterprise Risk Management - Labor Relations"*.

"**ICC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Principal Markets & Regulatory Environments".*

"**IESO**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Business Development - Principal Market Environment".*

"**Independent Board Committee**" has the meaning ascribed thereto under *"Description of Business - Business Associations with Apmi and Senior Executives".*

"**In-the-Money Amount**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**ISO**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

"**ISO-NE**" has the meaning ascribed thereto under the heading *"Description of the Business - 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 2013 - Distribution Group".*

"**ITC**" or "**Investment Tax Credit**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Business Development - Principal Market Environment".*

"**IUB**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Principal Markets & Regulatory Environments".*

"**JPMVEC**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities - Sandy Ridge Wind Facility".*

"**kV**" means a kilovolt.

"**Laclede**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**Liberty Energy (NH)**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Liberty Midstates**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**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 *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**LPSCo System**" has the meaning ascribed thereto under *""Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**LS Partnership**" means Algonquin Power (Long Sault) Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**LSR Royalty Interest**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Other Interests in Energy Related Developments"*.

"**LSR Subordinate Note**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Other Interests in Energy Related Developments"*.

"**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.

"**Market Price**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Market Purchase**" has the meaning ascribed thereto under *"Dividends - Dividend Reinvestment Plan".*

"**MBR Authority**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**MD&A**" has the meaning ascribed thereto under Schedule "F".

"**MDPU**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Principal Markets & Regulatory Environments".*

"**Merger**" has the meaning ascribed thereto "*Description of Capital Structure - Stock Option Plan*".

"**MGP**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Environmental Risks - Distribution Group".*

"**MISO**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

"**Midstates Gas Systems**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

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

"**MIPSA**" has the meaning ascribed thereto under *"Material Contracts"*.

"**MMBTU**" means one million British Thermal Units.

"Mont-Laurier Hydro Facility" means Mont-Laurier hydroelectric generating facility.

"**Mont-Laurier Partnership**" means Algonquin Power (Mont-Laurier) Limited Partnership. See *"Description of Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities"*.

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

"**Morse Wind Project**" means the Morse wind energy projects under development by APCo.

"**MPS**" has the meaning ascribed thereto under *"Description of the Business - Business Associations with APMI and Senior Executives".*

"**MNPSC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"MPSC has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**MW**" means megawatt.

"National Grid" means National Grid USA

"**NB Power**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods".*

"**NBSO**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods".*

"**New England Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Distribution Business Group".*

"**NHDES**" has the meaning ascribed thereto under *"Enterprise Risk Management - Environmental Risks - Distribution Group".*

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

"**NI 52 100**" has the meaning ascribed thereto under Schedule "F".

"**Northeast Expansion LLC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Transmission Group".*

"**Northern Maine Gen Co.**" means Algonquin Northern Maine Gen Co., a Wisconsin company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**NU**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Natural Gas Distribution Systems".*

"Odell SponsorCo" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships- Subsidiaries".*

"**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 System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

"**Parties**" has the meaning ascribed thereto under "*Description of the Business - Business Associations with APMI and Senior Executives*" .

"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 - Distribution Business Group".*

"**PG&E**" means Pacific Gas & Electric Company. See *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**PGA**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Material Facilities".*

"**PHMSA**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Environmental Risks - Distribution Group".*

"**Pine Bluff Water System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Distribution Business Group".*

"**PJM**" means PJM Interconnection. See *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

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

"**Power Pool**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods".*

"**PPA**" has the meaning ascribed thereto under *"General Development of the Business - General - Business Strategy".*

"**Primary Energy Production Hedge**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities- Material Facilities".*

"**Project**" has the meaning ascribed thereto under " *Description of Business - Transmission Group - Description of Operations* ".

"**PSNH**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Natural Gas Distribution Systems".*

"**PSU**" has the meaning ascribed thereto under " *Description of Capital Structure - Performance Share Units* ".

"**PTAM**" 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".*

"**PTC**" or "**Production Tax Credits**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Business Development".*

"**PUC Texas**" 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".*

"**PUHCA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**PURPA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**QFs**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**Quebec CRCE Tax Credit**" - has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"Rattle Brook Hydro Facility" has the meaning ascribed thereto under *"Description of the Business - Business Associations with APMI and Senior Executives"*

"**Rating Agencies**" means collectively DBRS, and S&P, and "Rating Agency" menas one of the Rating Agencies.

"**Rawdon Hydro Facility**" means the Rawdon hydroelectric generating facility.

"**REA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Business Development - Current Development Projects".*

"**REC**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Renewable Energy Credits".*

"**Red Lily II LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Red Lily Wind Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

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

"**RFP**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Business Development - Principal Market Environment".*

"**RGGI**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Generation Group".*

"Rights Plan" has the meaning ascribed thereto under *"Description of Capital Structure - Shareholders' Rights Plan"*.

"**Rio Rico System**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

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

"**RTOs**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

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

"**Saint-Damase GP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**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".*

"**Sanger Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**SaskPower**" means Saskatchewan Power Corporation.

"Seaway Management" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Côte Ste-Catherine Water Lease Dues***.**

"September Offering" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate - Issuance of Common Shares".*

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

"S.E.N.C." has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Senior Executives**" has the meaning ascribed thereto under *"Description of the Business - Business Associations with APMI and Senior Executives"*.

"**Series 2A Debentures**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate"*.

"**Series 2A Redemption Date**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate"*.

"**Series 3 Debentures**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate"*.

"**Series 3 Redemption Date**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate"*.

"**Series A Shares**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate"*.

"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 *"'General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group"*.

"**Share Reorganization**" has the meaning ascribed thereto "*Description of Capital Structure - Stock Option Plan*".

"SKIC 20" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**St. Alban Hydro Facility**" means the St. Alban hydroelectric generating facility.

"**Ste. Brigitte Hydro Facility**" means the St. Brigitte hydroelectric generating facility.

"**Steelworkers**" has the meaning ascribed thereto under *"Enterprise Risk Management - Labour Relations"*.

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

"**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"*.

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

"**St. Leon Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Stock Option Plan**" has the meaning ascribed thereto under the heading "*Description of Capital Structure - Stock Option Plan*".

"Strategic Investment Agreement" has the meaning ascribed thereto under the heading *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate"*.

"**Subscription Receipts**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate".*

"**Successor Corporation**" has the meaning ascribed thereto "*Description of Capital Structure - Stock Option Plan*".

"**SWRCB**" 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".*

"**Tax Partner**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**TCE**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Distribution Group".*

"**TCEQ**" 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".*

"**Tennessee**" has the meaning ascribed thereto under *"Description of the Business - Transmission Group - Description of Operations - Natural Gas Pipeline Transmission - Investments".*

"**Tinker Gen Co.**" means Algonquin Tinker Gen Co., a Wisconsin company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Tinker Hydro Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**TMC**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Long Sault Global Adjustment Claim"*.

"**TMO**" has the meaning ascribed thereto under *"Risk Factors - Acquisitions and Divestitures"*.

"**Trafalgar**" has the meaning ascribed thereto under "*Description of the Business - Business Associations with APMI and Senior Executives"* .

"**Trafalgar Hydro Facilities**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Trafalgar Proceedings"*.

"**Transmission Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Treasury Purchase**" has the meaning ascribed thereto under *"Dividends - Dividend Reinvestment Plan".*

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

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

"Unit Exchange Transaction" has the meaning ascribed thereto under *"Enterprise Risk Management - Financial Risk Management - Tax Risk and Uncertainty".*

"**USDOE**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Competitive Conditions".*

"**U.S. Wind Portfolio Facilities**" has the meaning ascribed thereto under "*Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**UWUA**" has the meaning ascribed thereto under *"Risk Factors - Labour Relations"*.

"**Val-Eo Partnership**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Valley Power Thermal Facility** " has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Vestas**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

"**WCI**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Generation Group".*

"**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 *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities" - Material Facilities".*

"Windsor Locks Thermal Facility" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**WE HoldCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**WP HoldCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"WP SponsorCo" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**WPPI**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

"**WP SponsorCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships- Subsidiaries".*

Consolidated Financial Statements of
Algonquin Power & Utilities Corp.
For the years ended December 31, 2014 and 2013

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, 2014, 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, 2014.

March 16, 2015

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the 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, 2014 and 2013 and the consolidated statements of operations, comprehensive income, equity, and cash flows for the years then ended, 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 audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for the years then ended, 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, 2014, 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 16, 2015 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 16, 2015



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

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2014, 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 United States generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, 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, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for the years then ended of Algonquin Power & Utilities Corp. and our report dated March 16, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Chartered Professional Accountants,
Licensed Public Accountants
Toronto, Canada
March 16, 2015



A member firm of Ernst & Young Global Limited

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,273	$ 13,839
Accounts receivable, net (note 4)	188,573	160,636
Natural gas in storage (note 1(g))	31,550	25,609
Supplies and consumables inventory	11,825	7,924
Regulatory assets (note 7)	61,645	26,125
Prepaid expenses	10,431	11,341
Notes receivable (note 8)	2,966	598
Deferred income taxes (note 20)	7,210	19,652
Income taxes receivable (note 20)	568	379
Derivative instruments (note 25)	10,688	9,176
Assets held for sale (note 17)	—	23,927
	334,729	299,206
Property, plant and equipment, net (note 5)	3,278,422	2,708,704
Intangible assets, net (note 6)	54,011	54,416
Goodwill (note 6)	92,328	84,647
Regulatory assets (note 7)	187,699	164,223
Derivative instruments (note 25)	31,782	27,123
Long-term investments (note 8)	43,279	32,746
Deferred income taxes (note 20)	57,065	86,632
Other assets (note 12)	35,100	18,784
	$ 4,114,415	$ 3,476,481

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 68,540	$ 14,489
Accrued liabilities	199,374	146,338
Dividends payable (note 16)	25,395	17,535
Regulatory liabilities (note 7)	20,590	21,632
Long-term liabilities (note 9)	9,130	8,339
Pension and other post-employment benefits (note 10)	333	305
Other long-term liabilities (note 13)	9,873	7,451
Advances in aid of construction (note 1(o))	1,149	1,239
Derivative instruments (note 25)	5,183	2,492
Environmental obligations (note 23(a)(ii))	19,643	10,111
Preferred shares, Series C (note 11)	1,085	1,038
Liabilities held for sale (note 17)	—	1,471
Income taxes liability (note 20)	3,633	5,159
Deferred credits (note 13)	18,638	7,778
Deferred income taxes (note 20)	3,702	2,308
	386,268	247,685
Long-term liabilities (note 9)	1,270,893	1,247,249
Advances in aid of construction (note 1(o))	79,955	77,697
Regulatory liabilities (note 7)	102,196	101,657
Deferred income taxes (note 20)	130,758	137,153
Derivative instruments (note 25)	40,088	13,729
Deferred credits (note 13)	13,624	17,115
Pension and other post-employment benefits (note 10)	138,602	70,532
Environmental obligation (note 23(a)(ii))	52,662	59,444
Other long-term liabilities (note 13)	33,227	20,492
Preferred shares, Series C (note 11)	17,608	17,767
	1,879,613	1,762,835
Redeemable non-controlling interest (note 3(c))	12,146	—
Equity:		
Preferred shares (note 14(b))	213,805	116,546
Common shares (note 14(a))	1,633,262	1,351,264
Subscription receipts (note 14(a)(iii))	110,503	—
Additional paid-in capital	33,068	7,313
Deficit	(505,305)	(488,406)
Accumulated other comprehensive income (loss) (note 15)	34,213	(31,410)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,519,546	955,307
Non-controlling interests	316,842	510,654
Total Equity	1,836,388	1,465,961
Commitments and contingencies (note 23)		
Subsequent events (notes 3(a), 14(c)(iv) and 20)		
	$ 4,114,415	$ 3,476,481

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	
	2014	**2013**
Revenue		
Regulated electricity distribution	$ 206,667	$ 166,156
Regulated gas distribution	446,025	260,424
Regulated water reclamation and distribution	66,419	57,350
Non-regulated energy sales	202,300	180,191
Other revenue	22,149	11,170
	943,560	675,291
Expenses		
Operating	235,984	180,346
Regulated electricity purchased	120,506	97,376
Regulated gas purchased	261,116	148,784
Non-regulated energy purchased	39,264	25,835
Administrative expenses	34,692	23,518
Depreciation of property, plant and equipment	108,974	91,978
Amortization of intangible assets	4,626	4,200
Other amortization	447	(159)
Gain on foreign exchange	(1,112)	(567)
	804,497	571,311
Operating income from continuing operations	139,063	103,980
Interest expense	62,418	53,426
Interest, dividend income and other income	(7,758)	(7,785)
Loss (gain) on sale of assets	(436)	750
Acquisition-related costs	2,552	2,140
Write-down of long-lived assets	8,463	—
Loss (gain) on derivative financial instruments (note 25(b)(iv))	1,375	(5,200)
	66,614	43,331
Earnings from continuing operations before income taxes	72,449	60,649
Income tax expense (note 20)		
Current	3,674	2,526
Deferred	13,133	6,629
	16,807	9,155
Earnings from continuing operations	55,642	51,494
Loss from discontinued operations, net of tax (note 17)	(2,127)	(42,011)
Net earnings	53,515	9,483
Net loss attributable to non-controlling interests (note 19)	(22,186)	(10,813)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 75,701	$ 20,296
Basic net earnings per share from continuing operations (note 21)	$ 0.32	$ 0.28
Basic net loss per share from discontinued operations (note 21)	(0.01)	(0.21)
Basic net earnings per share (note 21)	0.31	0.07
Diluted net earnings per share from continuing operations (note 21)	0.32	0.28
Diluted net loss per share from discontinued operations (note 21)	(0.01)	(0.20)
Diluted net earnings per share (note 21)	$ 0.31	$ 0.07

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2014	2013
Net earnings	$ 53,515	$ 9,483
Other comprehensive income:		
Foreign currency translation adjustment, net of tax recovery of $1,049 and tax expense of $149, respectively (notes 1(v), 25(b)(iii) and 25(c))	100,548	81,597
Change in fair value of cash flow hedge, net of tax expense of $7,638 and $5,103, respectively (note 25(b)(ii))	6,434	17,308
Change in unrealized appreciation in value of available-for-sale investments	1	—
Change in pension and other post-employment benefits, net of tax recovery of $22,446 and tax expense of $10,896, respectively (note 10)	(35,669)	16,727
Other comprehensive income, net of tax	71,314	115,632
Comprehensive income	124,829	125,115
Comprehensive income attributable to the non-controlling interests	7,077	31,362
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 117,752	$ 93,753

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, 2014

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

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2013

	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, 2012	$ 1,245,326	$ 116,546	$ 61,160	$ 5,224	$ (406,143)	$ (104,867)	$ 484,883	$ 1,402,129
Net earnings (loss)	—	—	—	—	20,296	—	(10,813)	9,483
Other comprehensive income	—	—	—	—	—	73,457	42,175	115,632
Dividends declared and distributions to non-controlling interests	—	—	—	—	(59,773)	—	(5,591)	(65,364)
Dividends and issuance of shares under dividend reinvestment plan	13,970	—	—	—	(13,970)	—	—	—
Exercise and conversion of subscription receipts	90,464	—	(90,464)	—	—	—	—	—
Issuance of subscription receipts (note 14(a)(iii))	—	—	29,304	—	—	—	—	29,304
Conversion and redemption of convertible debentures	960	—	—	—	—	—	—	960
Issuance of common shares under employee share purchase plan	544	—	—	—	(17)	—	—	527
Share-based compensation expense	—	—	—	2,089	—	—	—	2,089
Preferred shares, Series C (note 11)	—	—	—	—	(18,497)	—	—	(18,497)
Acquisition of non-controlling interest (note 18)	—	—	—	—	(10,302)	—	—	(10,302)
Balance, December 31, 2013	$ 1,351,264	$ 116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$ 510,654	$ 1,465,961

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	Year ended December 31	
	2014	2013
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 55,642	$ 51,494
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	108,974	91,978
Amortization of intangible assets	4,626	4,200
Other amortization	1,799	2,891
Deferred taxes	13,133	6,629
Unrealized loss (gain) on derivative financial instruments	3,046	(6,758)
Share-based compensation	3,203	2,000
Cost of equity funds used for construction purposes	(1,910)	(1,786)
Pension and post-employment expense	(2,050)	(302)
Write-down of long-lived assets	8,463	—
Loss on sale of long-lived assets	—	750
Changes in non-cash operating items (note 24)	(1,790)	(47,819)
Changes in non-cash operating items from discontinued operations (note 24)	1,262	36
Cash used in discontinued operations (note 17)	(1,682)	(4,388)
	192,716	98,925
Financing Activities		
Cash dividends on common shares	(57,848)	(52,335)
Cash dividends on preferred shares	(9,503)	(5,400)
Cash contributions from non-controlling interests	11,845	—
Production based cash contributions from non-controlling interest	8,976	1,672
Cash distributions to non-controlling interests	(4,738)	(7,263)
Issuance of common shares, net of costs	261,452	29,983
Proceeds from subscription receipts	110,503	—
Issuance of preferred shares, net of costs	96,271	—
Deferred financing costs	(3,043)	(2,240)
Increase in deferred insurance proceeds & revenue	13,132	—
Acquisition of non-controlling interest	(127,121)	—
Increase in long-term liabilities	236,528	950,346
Decrease in long-term liabilities	(286,552)	(685,472)
Increase (decrease) in advances in aid of construction	(48)	2,299
Increase (decrease) in other long-term liabilities	5,486	(1,574)
	255,340	230,016
Investing Activities		
(Increase) decrease in restricted cash	(11,034)	1,430
Increase in other assets	(2,751)	(3,004)
Distributions received in excess of equity income	264	727
Proceeds from sale of discontinued operations	20,826	24,968
Receipt of principal on notes receivable	280	109
Additions to property, plant and equipment	(432,373)	(158,377)
Acquisitions of long-term investments	(25,432)	—
Acquisitions of operating entities	(8,757)	(239,014)
Proceeds from sale of investment	5,709	3,408
	(453,268)	(369,753)
Effect of exchange rate differences on cash	646	1,529
Decrease in cash and cash equivalents	(4,566)	(39,283)
Cash and cash equivalents, beginning of year	13,839	53,122
Cash and cash equivalents, end of year	$ 9,273	$ 13,839

Supplemental disclosure of cash flow information:	2014	2013
Cash paid during the year for interest expense	$ 60,682	$ 44,185

Cash paid during the year for income taxes	$	2,571	$	1,107
Non-cash transactions: Property, plant and equipment acquisitions in accruals	$	25,568	$	10,829

See accompanying notes to consolidated financial statements

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

1. Significant accounting policies

(a) Basis of preparation

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

(b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary (note 1(m)). Intercompany transactions and balances have been eliminated.

(c) 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 commissions 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 revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

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

The electric and gas utilities' and the 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, respectively.

(d) Cash and cash equivalents

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

(e) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash as part of other assets (note 12) in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

1. Significant accounting policies (continued)

(f) 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.

(g) 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. Existing rate orders allow the Company to pass through the cost of gas purchased directly to the rate payers 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 (note 7(d)).

(h) 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.

(i) Property, plant and equipment

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, gas, water and wastewater distribution assets, equipment and land, are recorded at cost. 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 equity funds used during construction ("AFUDC") for regulated property. 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 and other income on the consolidated statements of operations.

	2014	2013
Interest capitalized on non-regulated property	**$ 3,584**	$ 669
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,577**	1,055
Allowance for equity funds	**1,910**	1,786
Total	**$ 7,071**	$ 3,510

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. 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.

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued)

Investment tax credits and government grants 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 1(o)) 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.

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. The ranges of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2014	2013	2014	2013
Generation Group				
Renewable	**3 – 60**	3 – 60	**36**	35
Thermal	**3 – 40**	3 – 40	**25**	24
Distribution Group				
Gas	**5 – 100**	5 – 80	**41**	38
Electrical	**5 – 75**	8 – 75	**41**	41
Water & wastewater	**5 – 75**	5 – 50	**39**	39
Equipment	**5 – 50**	5 – 50	**14**	24

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

(j) Intangible assets

The fair value of power sales contracts acquired in business combinations is amortized on a straight-line basis over the remaining term of the contract. The periods range from 6 to 25 years from the date of acquisition.

Customer relationships acquired in business combinations are amortized on a straight-line basis over their estimated life of 40 years.

(k) Goodwill

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

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

1. Significant accounting policies (continued)

(l) Impairment of long-lived assets

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

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 the 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.

(m) Variable interest entities

The Company performs analyses 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. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated (note 8(a)).

The Long Sault Hydroelectric Facility ("Long Sault") is a hydroelectric generating facility in which APUC acquired an interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 70% after tax cash flows of the facility from 2014 to 2027 and 62.5% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. Effective December 31, 2013, APUC acquired an equity interest in Long Sault (note 18). APUC has determined that the facility is a VIE. Since the Company is the primary beneficiary, the Long Sault entity is subject to consolidation by the Company. Total net book value of generating assets and long-term debt of Long Sault amounts to $42,689 (2013 - $44,319) and $36,049 (2013 - $37,143), respectively. The Long Sault debt only has recourse over the Long Sault generating assets. The financial performance of Long Sault reflected on the consolidated statements of operations includes non-regulated energy sales of $10,778 (2013 - $10,155), operating expenses and amortization of $3,201 (2013 - $2,391) and interest expense of $3,781 (2013 - $3,632).

The Saint-Damase Wind Powered Generating Facility ("Saint-Damase") is a 24 megawatt ("MW") wind powered generating facility located near St. Damase, Quebec which achieved commercial operation on December 2, 2014. The Company owns a 50% interest in the corporation with the remaining 50% interest held by the Municipality of Saint-Damase. The Company also provided subordinated construction loans to the project. APUC has determined that the corporation holding the facility is a VIE. Since the Company is the primary beneficiary, Saint- Damase is subject to consolidation by the Company. Total net book value of generating assets and third-party long-term debt of Saint-Damase amounts to $69,655 and $23,400, respectively. The financial performance of Saint-Damase reflected on the consolidated statements of operations for its first month of operations in 2014 includes non-regulated energy sales of $440, operating expenses and amortization of $217 and interest expense of $39.

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but are not controlled 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 and other income in the consolidated statements of operations.

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable (continued)

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

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

(o) 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. These amounts are recorded as Advances in aid of construction on the consolidated balance sheet.

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 10 to 20 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2014, $4,608 (2013 - $627) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Deferred water rights and customer deposits

Deferred water rights are related to a hydroelectric generating facility which has a fifty-year water lease with the first ten years of the water lease requiring no payment, which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

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. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be creditworthy.

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

1. Significant accounting policies (continued)

(r) 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, construction, development 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 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 accumulated obligation.

(s) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee share-based compensation as a cost in the consolidated financial statements. 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.

(t) Non-controlling interests

Non-controlling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent company. Non-controlling interests are initially recorded at fair value and subsequently the amount is 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.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. The HLBV method uses a balance sheet approach, which measures the allocation of income or loss of the Class A partnership units in each period by calculating the change in the amount of distribution the partners would contractually be entitled to based on a hypothetical liquidation of the book value carrying amounts of the entity at the beginning of a reporting period compared to the end of that period (note 19).

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a 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.

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. At each balance sheet date, 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 accumulated deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

1. Significant accounting policies (continued)

(u) 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.

Revenues related to utility electricity and natural gas sales and distribution are recorded based on metered consumptions by customers, which occur on a systematic basis throughout a month, rather than 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 revenues are calculated. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Revenue for the Company's Calpeco Electric System, Peach State and New England Gas Systems is subject to a revenue decoupling mechanism approved by their respective regulator which require to charge approved annual delivery revenues 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(j)).

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 revenues are calculated. These estimates of unbilled revenues 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 sale taxes.

During the year, the Company settled insurance claims for business interruption at some of its renewable generation facilities under repairs and as a result recognized revenue of $1,227 (2013 - $6,455).

(v) Foreign currency translation

The Company’s reporting currency is the Canadian dollar.

The Company’s U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenues and expenses are translated using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

1. Significant accounting policies (continued)

(w) 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. Investment tax credits are recorded as an offset to the related long-lived asset and are amortized over the estimated life of the asset as credits to income tax expense.

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.

(x) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, Series C preferred shares and other long-term liabilities 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 respective asset's carrying value at inception. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's revolving credit facilities and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. 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 are amortized on a straight-line basis over the term of the respective revolving credit facility.

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

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as 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 recognized in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecast transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

1. Significant accounting policies (continued)

(x) Financial instruments and derivatives (continued)

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.

Calpeco Electric System and Granite State Electric System enter into power purchase agreements ("PPA") for load serving 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.

(y) 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 measurement date.

(z) Commitments and contingencies

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

(aa) 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 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This newly issued accounting standard requires an entity to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit as a reduction to a deferred income tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. This newly issued accounting standard permits the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to interest rates on direct Treasury obligations of the U.S. government and the London Interbank Offered Rate. The amendments also remove the restriction on using different benchmark rates for similar hedges. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. This newly issued accounting standard provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

(b) Recent accounting guidance not yet adopted

The FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which ends the deferral granted to investment companies from applying the VIE guidance and makes targeted amendments to the current consolidation guidance. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the VIE characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This ASU may be applied using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-01, Income Statement: Extraordinary and Unusual Items (Subtopic 225-20), to simplify income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. This ASU may be applied prospectively or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted, but only as of the beginning of the fiscal year of adoption. The adoption of this standard is not expected to have an impact on the Company's results of operations.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted (continued)

The FASB issued ASU No. 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 No. 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 No. 2014-16 clarifies that in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (that is, the relative strength of the debt-like or equity-like terms and features given the facts and circumstances) when considering how to weigh those terms and features. The effects of initially adopting ASU No. 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in a form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. ASU No. 2014-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2014-15, Presentation of Financial Statements — Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity's management should evaluate whether there are conditions or events, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. This ASU will be effective for the annual reporting period ending after December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This newly issued accounting standard is intended to resolve the diverse accounting treatment of those awards in practice. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2015. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB and the International Accounting Standards Board have jointly issued a new revenue recognition standard codified in U.S. GAAP as ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2016 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company is currently assessing the impact the adoption of this standard might have on its financial position or results of operations.

The FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This newly issued accounting standard raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This ASU is required to be applied prospectively for fiscal years and interim periods beginning after December 15, 2014. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

3. Business acquisitions and development projects

(a) Acquisition of New Hampshire Gas

Subsequent to year-end , the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. $3,047, subject to certain closing adjustments.

(b) Agreement to acquire Park Water System

On September 19, 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company (“Park Water System”). 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. Total consideration for the utility purchase is expected to be approximately U.S. $327,000, which includes the assumption of approximately U.S. $77,000 of existing long-term utility debt and is subject to certain working capital and other closing adjustments. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in the latter half of 2015.

(c) Development of Bakersfield Solar Project

During the year, the Company constructed a 20 MWac solar powered generating facility located in Kern County, California. As of December 31, 2014, the Company has incurred U.S $56,814 in the development and construction of the solar energy project which is recorded as property, plant and equipment. The facility was placed in service on December 31, 2014. Sales of power to the utility under the power purchase agreement is planned for early 2015.

On August 13, 2014, the Generation Group entered into a definitive partnership agreement with a third-party (the "Tax Investor"). It is anticipated that approximately U.S. $22,800 will be funded by the Tax Investor. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the project. The Tax Equity investment as of December 31, 2014 is U.S. $10,470.

Under certain conditions, the Tax Investor has the right to withdraw from the Bakersfield Solar Project and require the Company to redeem its interests for cash over a contractual payment period. As a result, the Company accounts for this interest as temporary equity and records this interest outside of permanent equity on the consolidated balance sheets as "Redeemable non-controlling interest". The Company records temporary equity at issuance based on cash received less any transaction costs. As of December 31, 2014, transaction costs of $956 have been recorded as a reduction to Redeemable non-controlling interest.

At each balance sheet date, the Company will reevaluate the classification of its redeemable instrument, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company will record the instruments at its redemption value. Increases or decreases in the carrying amount of a redeemable instrument will be recorded within accumulated deficit. Redemption is not considered probable as of December 31, 2014.

(d) Commercial operation of Saint-Damase Wind Facility

Saint-Damase is a 24 MW wind powered generating facility located near St. Damase, Quebec which achieved commercial operation on December 2, 2014. Total net book value of generating assets of Saint-Damase amounts to $69,655. Property, plant and equipment are amortized over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Saint-Damase Wind Generating Facility is 35 years.

3. Business acquisitions and development projects (continued)

(e) Commercial operation of Cornwall Solar Facility

On March 27, 2014, the Cornwall Solar Facility, a 10 MWac solar powered generating facility located near Cornwall, Ontario, commenced commercial operations. The Company invested $41,551 in the development and construction of the solar energy project which is recorded as property, plant and equipment, as well as additional amounts related to development rights and other intangible assets, for a total investment of $47,561. Property, plant and equipment are amortized over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Cornwall Solar Powered Facility is 33 years.

(f) Acquisition of White Hall Water System

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

(g) Acquisition of non-controlling interest in U.S. Wind farms

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

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

(h) Acquisition of New England Gas System

On December 20, 2013, the Company acquired certain regulated natural gas distribution utility assets (the “New England Gas System”) located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is $67,010 (U.S. $62,745), including the purchase price adjustment of U.S. $3,108 finalized in Q2 2014.

3. Business acquisitions and development projects (continued)

(h) Acquisition of New England Gas System (continued)

In 2014, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed. The carrying value of those assets and liabilities were retrospectively adjusted to the amounts detailed in the table below. The key adjustments were an increase to the regulatory asset for pension of U.S. $4,642, a decrease of property, plant and equipment of U.S. $1,190, an increase of the environmental obligation of U.S. $4,408 and an increase of the pension obligation of U.S. $772.

Working capital	$	7,543
Restricted cash		595
Property, plant and equipment		83,365
Regulatory assets		52,601
Other assets		1,221
Long-term debt		(25,349)
Regulatory liabilities		(9,874)
Pension and OPEB		(26,184)
Environmental obligation		(14,933)
Deferred income tax liability, net		(1,158)
Other liabilities		(817)
Total net assets acquired	$	67,010

The determination of the fair value is based upon management's estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed.

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 New England Gas System assets is 31 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

The New England Gas System contributed revenue of $91,782 (2013 - $3,582) and net earnings of $10,819 (2013 - $1,153) to the Company's consolidated financial results for 2014.

(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 2015. 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, a gain of U.S. $1,133 was recognized in 2014.

4. Accounts receivable

Accounts receivable as of December 31, 2014 include unbilled revenue of $52,880 (December 31, 2013 - $45,274) from the Company's regulated utilities. Accounts receivable as of December 31, 2014 are presented net of allowance for doubtful accounts of $7,229 (December 31, 2013 - $8,461).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2014	Cost	Accumulated depreciation	Net book value
Generation Group			
Renewable	$ 1,697,020	$ 217,615	$ 1,479,405
Thermal	130,227	53,131	77,096
Distribution Group			
Water & wastewater	358,520	78,290	280,230
Electricity	347,633	23,659	323,974
Gas	849,136	45,777	803,359
Land	19,347	—	19,347
Equipment and other	119,367	29,526	89,841
Construction in progress			
Generation	82,840	—	82,840
Distribution	122,330	—	122,330
	$ 3,726,420	$ 447,998	$ 3,278,422

2013	Cost	Accumulated depreciation	Net book value
Generation Group			
Renewable	$ 1,438,229	$ 166,175	$ 1,272,054
Thermal	116,975	43,596	73,379
Distribution Group			
Water & wastewater	303,410	63,807	239,603
Electricity	277,679	16,782	260,897
Gas	682,445	15,769	666,676
Land	8,266	—	8,266
Equipment and other	78,881	29,100	49,781
Construction in progress			
Generation	54,432	—	54,432
Distribution	83,616	—	83,616
	$ 3,043,933	$ 335,229	$ 2,708,704

Renewable generation assets include cost of $155,629 (2013 - $86,774) and accumulated depreciation of $34,013 (2013 - $31,739) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,274 (2013 - $2,155).

Investments tax credits, government grants and contributions received in aid of construction of $362 (2013 - $3,098) have been credited to the cost of the distribution 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:

2014	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 64,605	$ 33,704	$ 30,901
Customer relationships	31,094	7,984	23,110
	$ 95,699	$ 41,688	$ 54,011

2013	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 61,430	$ 28,987	$ 32,443
Customer relationships	28,512	6,539	21,973
	$ 89,942	$ 35,526	$ 54,416

Estimated amortization expense for intangible assets for the next two years is $4,750 each year, $3,000 in year three, $2,640 in year four and $2,580 in year five.

Changes in goodwill are as follows:

	Distribution Group
Balance, January 1, 2013	$ 61,459
Business acquisitions	17,260
Adjustments	748
Foreign exchange	5,180
Balance, December 31, 2013	$ 84,647
Foreign exchange	7,681
Balance, December 31, 2014	$ 92,328

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 revenues 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.

7. Regulatory matters (continued)

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

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

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

On December 4, 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S. $3,680 in connection with its annual GRAM filing on October 1, 2014. The new rates are effective as of February 1, 2015.

Regulatory assets and liabilities consist of the following:

		2014		2013
Regulatory assets				
Environmental costs (a)	**$**	**102,735**	$	85,029
Pension and post-employment benefits (b)		**65,745**		64,997
Storm costs (c)		**3,080**		5,437
Commodity costs adjustment (d)		**41,502**		15,904
Rate case costs (e)		**4,161**		3,119
Vegetation management		**3,260**		2,297
Debt premium (f)		**4,658**		4,504
Rate adjustment mechanism (j)		**6,207**		28
Asset retirement obligation (g)		**1,682**		1,468
Tax related		**4,350**		2,995
Other		**11,964**		4,570
Total regulatory assets	**$**	**249,344**	$	190,348
Less current regulatory assets		**(61,645)**		(26,125)
Non-current regulatory assets	**$**	**187,699**	$	164,223
Regulatory liabilities				
Cost of removal (h)	**$**	**78,013**	$	68,698
Rate-base offset (i)		**23,427**		25,082
Commodity costs adjustment (d)		**10,389**		17,394
Pension and post-employment benefits (b)		**592**		6,770
Rate adjustment mechanism (j)		**448**		1,681
Storm costs (c)		**1,030**		—
Depreciation adjustment mechanism		**3,518**		—
Tax related		**145**		133
Other		**5,224**		3,531
Total regulatory liabilities	**$**	**122,786**	$	123,289
Less current regulatory liabilities		**(20,590)**		(21,632)
Non-current regulatory liabilities	**$**	**102,196**	$	101,657

7. Regulatory matters (continued)

(a) Environmental remediation costs recovery: Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 23 (a)(ii)) are recovered through rates over a period of 7 years and in a jurisdiction are subject to an annual cap.

(b) Pension and post-employment benefits: As part of 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 $28,284 relates to a recent acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order in 2015. The balance is recovered through rates over the future services years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation-Nonretirement Postemployment Benefits and ASC 715 Compensation-Retirement Benefits before the transfer to regulatory asset occurred.

(c) Storm costs: Incurred repair costs resulting from certain storms over or under amounts collected from customers, which are expected to be recovered or refunded through rates.

(d) Commodity costs adjustment: The revenue of the electric and natural gas utilities includes a component which is designed to recover the cost of electricity or natural gas through rates charged to customers. Under deferred energy accounting, to the extent actual natural gas and purchased power costs differ from natural gas and purchased power costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25(b)(i)) are recoverable through the commodity costs adjustment.

(e) 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.

(f) Debt premium: The value of debt assumed in the acquisition of the New England Gas System has been recorded at fair value in accordance with ASC 805 Business Combinations. The Massachusetts regulator allows for recovery of interest at the coupon rate of the debt and a regulatory asset has been recorded for the difference between the fair value and face value of the debt. The debt premium is recovered over the remaining term of the debt (note 9).

(g) Asset retirement obligation: Asset retirement obligations incurred by the utilities are expected to be recovered through rates.

(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 would reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of ten years.

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

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

8. Long-term investments

Long-term investments consist of the following:

	2014	2013
Equity-method investees		
50% interest in Odell Wind Project (a)	**$ 2,267**	$ —
2.5% interest in natural gas pipeline development (b)	**1,063**	—
32.4% of Class B non-voting shares of Kirkland Lake Power Corp. (c)	**1,512**	4,851
25% of Class B non-voting shares of Cochrane Power Corporation (c)	**—**	3,772
50% interest in the Valley Power Partnership	**1,253**	1,718
Other	**640**	325
Total	**$ 6,735**	$ 10,666
Notes receivable		
Development loans (a)	**$ 17,582**	$ —
Red Lily Senior loan, interest at 6.31% (d)	**11,588**	11,588
Red Lily Subordinated loan, interest at 12.5% (d)	**6,565**	6,565
Chapais Énergie, Société en Commandite interest at 10.789%	**649**	1,928
Silverleaf resorts loan, interest at 15.48% maturing July 2020	**2,344**	2,149
Other	**782**	448
	39,510	22,678
Less current portion	**(2,966)**	(598)
Total	**$ 36,544**	$ 22,080
Total long-term investments	**$ 43,279**	$ 32,746

(a) Odell Wind Project

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

On the acquisition of the Odell Wind Project by Odell SponsorCo, the two members each contributed U.S. $1,000 to the capital of Odell SponsorCo. Upon execution of third-party construction loan and tax equity documents expected in the second quarter of 2015, each party will contribute another U.S. $23,800 to the capital of Odell SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments, on commencement of operations, which is expected in late 2015 or early 2016.

As of December 31, 2014, Odell SponsorCo is considered a VIE namely due to the low level of its equity at that point. The Company is not considered the primary beneficiary of Odell SponsorCo as the two members have joint control and all decisions must be unanimous. As such, the Company is accounting for the joint venture as an equity method investment. The Company's maximum exposure to loss is $311,966 as of December 31, 2014.

8. Long-term investments (continued)

(a) Odell Wind Project (continued)

The Company entered into a committed loan and credit support facility with Odell SponsorCo. During construction, the Company is obligated to provide Odell SponsorCo 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 Odell Wind Project. The loan bears interest at an annual rate of 8% on outstanding principal amount until commercial operation date and 5% thereafter until maturity date, and the letters of credit are charged an annual fee of 2% on their stated amount. Any loan outstanding to Odell SponsorCo, to the extent not otherwise repaid earlier, is repayable in cash on the fifth anniversary of the availability termination date which is thirty days following the commercial operation date.

As of December 31, 2014, the Company had loaned U.S. $13,159 to Odell SponsorCo for development costs of the Odell Wind Project. No interest revenue was accrued on the loan due to insufficient collateral in Odell SponsorCo. The following credit support was also issued by the Company: a U.S. $15,000 letter of credit on behalf of the Odell Wind Project, to the utility under the PPA; guarantee of the obligations of the Odell Wind Project under the wind turbine supply agreement between Odell SponsorCo and Vestas-American Wind Technology, Inc.; a U.S. $23,800 letter of credit on behalf of Odell SponsorCo, to Enel Kansas, LLC under the purchase and sale agreement. The guarantee obligations are recognized under other long-term liabilities and were valued at U.S. $720 using a probability weighted discounted cash flow (level 3).

(b) Natural Gas Pipeline Development

On November 24, 2014, APUC announced that it plans to participate in the development of Kinder Morgan Inc's proposed Northeast Energy Direct natural gas pipeline project. The Company and Kinder Morgan Operating L.P. "A" formed a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be constructed between Wright, NY and Dracut, MA. The pipeline capacity will be contracted with local distribution utilities, and other customers in the northeast U.S. The project is expected to reach commercial operations by late 2018. Under the agreement, APUC initially subscribed for a 2.5% interest in Northeast Expansion LLC with an opportunity to increase its participation up to 10%. The total capital investment assuming APUC exercises its right to subscribe for 10% of the pipeline is expected be up to U.S. $400,000, depending on the final pipeline configuration and design capacity by the end of 2018. As of December 31, 2014, APUC had invested U.S. $375 in Northeast Expansion LLC. The Company assessed that its interest of 2.5% in a limited liability corporation together with the option to increase its participation to 10% and the commitment from its New Hampshire subsidiary to a firm gas transportation agreement for service on the pipeline facilities provide significant influence. As such, the interest is accounted as an equity method investment.

(c) Kirkland Lake Power Corp. and Cochrane Power Corporation

In September 2014, the Company was informed that future cash flows from its investments in Kirkland Lake Power Corp. ("Kirkland") and Cochrane Power Corporation ("Cochrane") are likely to be significantly reduced in the future based on the current power purchase rates negotiations. As the loss in value of these investments is considered other than temporary, an allowance for impairment of $3,414 and $3,772 on Kirkland and Cochrane, respectively, was recorded in the consolidated statements of operations. The fair value of the investments (level 3) was estimated using cash flow information provided by the investees.

8. Long-term investments (continued)

(d) Red Lily I

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

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

The senior debt facility consists of two tranches. A third-party lender advanced $27,000 of senior debt to the Partnership as Tranche 1. In 2011, APUC advanced $13,000 of senior debt as Tranche 2 to the Partnership and received a pre-payment of $1,412 in 2012. Another third-party lender has also advanced $4,000 of senior debt Tranche 2 to the Partnership. The Company's senior loan Tranche 2 to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Tranche 1 is being repaid in equal blended monthly payments of principal and interest at a rate of 6.99% based upon a twenty-five year amortization. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

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

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including the Company's portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as of December 31, 2014 and 2013 was determined to be negligible.

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

9. Long-term liabilities

Long-term liabilities consist of the following:

	2014	2013
Generation Group		
$350,000 revolving credit facility, interest rate is equal to bankers' acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is BA or LIBOR plus 1.45%, maturing July 31, 2018.	**$ 23,400**	$ 124,570
Algonquin Power Co.: Senior Unsecured Notes: $200,000 bearing an interest rate of 4.65% maturing February 15, 2022; $150,000 bearing an interest rate of 4.82% maturing February 15, 2021; $135,000 bearing an interest rate of 5.50% maturing July 25, 2018. The notes have interest only payments, payable semi-annually in arrears.	**484,553**	284,757
Shady Oaks Wind Facility: Senior Debt: U.S. $76,000 Chinese Development Bank Corporation loan facility, bearing an interest rate of 6 month LIBOR plus 280 basis points, maturing June 30, 2026. The facility has principal and interest payments, payable semi-annually in arrears.	**88,168**	129,759
Long Sault Hydro Facility: Senior Debt: Bonds bearing an interest rate of 10.21% maturing December 31,2027. The bonds have interest and principal payments, payable monthly in arrears.	**36,048**	37,143
Sanger Thermal Facility: Senior Debt: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond Series 1990A, bearing an effective interest rate determined by the remarketing agent. The bond has interest only payments, payable monthly in arrears. The effective interest rate in 2014 was 2.01% (2013 – 1.72%). The bonds were fully repaid on December 31, 2014.	**—**	20,421
Chuteford Hydro Facility: Senior Debt: Bonds bearing an interest rate of 11.6%, maturing April 1, 2020. The bond has principal and interest payments, payable monthly in arrears.	**3,028**	3,417
Distribution Group		
U.S. $200,000 revolving credit facility, interest rate is equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.25%, maturing September 30, 2018.	**23,898**	85,620
Liberty Utilities Co.: Senior Unsecured Notes: U.S. $ 50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $ 25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; U.S. $ 15,000, bearing an interest rate of 4.14%, maturing March 13, 2023; U.S. $ 75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; U.S. $ 60,000, bearing an interest rate of 4.89%, maturing July 30, 2027; U.S. $ 25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The notes have interest only payments, payable semi-annually.	**423,436**	388,214

	2014	2013
Calpeco Electric System: Senior Unsecured Notes: U.S. $45,000 bearing an interest rate of 5.19%, maturing December 29, 2020; U.S. $25,000 bearing an interest rate of 5.59%, maturing December 29, 2025. The notes have interest only payments, payable semi-annually in arrears.	**81,207**	74,452
Liberty Water Co: Senior Unsecured Notes: U.S. $50,000 bearing an interest rate of 5.60% $5,000 matures annually beginning June 20, 2016; $25,000 maturing December 22, 2020. The note bears interest payments semi-annually in arrears.	**58,005**	53,180
New England Gas System: First mortgage bonds: U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.	**27,288**	25,244
Granite State Electric System: Senior unsecured notes: U.S. $5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; and, U.S. $5,000, bearing an interest rate of 7.30%, maturing June 15, 2028. The notes have interest only payments, payable semi-annually.	**17,402**	15,954
LPSCo Water System: 1999 and 2001 IDA Bonds bearing interest rates of 5.95% and 6.75% and maturing October 1, 2023 and October 1, 2031, respectively. The bonds have principal and interest payments, payable monthly in arrears.	**12,441**	11,668
Bella Vista Water System: Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10%, and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears.	**1,149**	1,189
	$ 1,280,023	$ 1,255,588
Less: current portion	**(9,130)**	(8,339)
	$ 1,270,893	$ 1,247,249

9. Long-term liabilities (continued)

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

Generation Group

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

On July 31, 2014, the Company increased the credit available under the senior unsecured revolving credit facility to $350,000 from $200,000. The larger revolving credit facility will be used to provide additional liquidity in support of the Generation Group's development portfolio to be completed over the next three years. The maturity of the revolving credit facility has been extended to July 31, 2018.

On January 17, 2014, the Company issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year, commencing on February 15, 2014. the Company incurred deferred financing costs of $1,568, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, the Company entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Company's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation is reported in the same manner as the translation adjustment (in OCI) related to the net investment (note 25(b)(iii)).

Effective January 1, 2013, concurrent with the acquisition of Shady Oaks Wind Facility (note 3(i)), the Company assumed existing long-term debt of approximately U.S. $150,000. Principal of U.S. $46,000 was repaid in 2014 leaving a balance of U.S. $76,000 outstanding as of December 31, 2014. The semi-annual principal repayment schedule for the following 11.5 years ranges from U.S. $3,000 to U.S. $6,000 with a final repayment in 2026. This debt may be repaid in whole or in part on an interest payment date, annually May 15 or November 15, without penalty.

Distribution Group

On December 20, 2013, in connection with the acquisition of the New England Gas System, the Company assumed first mortgage bonds of U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; and, U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020.

On September 30, 2013, the Company increased the maximum availability under its senior unsecured revolving credit facility from U.S. $100,000 to $200,000 to meet future working capital requirements and allow for greater financial flexibility. The revolving credit facility has a maturity date of September 30, 2018.

On July 31, 2013, the Company issued U.S. $125,000 of senior unsecured notes through a private placement in three tranches: U.S. $25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; and, U.S. $25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The proceeds from the private placement financing were used to fund a portion of the acquisition of the Peach State Gas System.

On March 14, 2013, the Company issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Pine Bluff Water System. The notes bear interest at 4.14% and mature March 13, 2023.

9. Long-term liabilities (continued)

APUC

On November 19, 2013, APUC increased the maximum availability under its senior unsecured revolving credit facility from U.S. $30,000 to $65,000. The revolving credit facility will be used for general corporate purposes and has a maturity date of November 19, 2016. As of December 31, 2014 and 2013, no amounts were outstanding under this revolving credit facility.

As of December 31, 2014, the Company had accrued $18,770 in interest expense (2013 - $14,057). Interest paid on the long-term liabilities in 2014 was $61,287 (2013 - $49,746).

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

	2015	2016	2017	2018	2019	Thereafter	Total
Generation Group	$ 8,599	$ 8,779	$ 11,300	$ 169,822	$ 12,132	$ 424,517	$ 635,149
Distribution Group	531	6,393	64,435	30,349	6,492	536,626	644,826
Total	$ 9,130	$ 15,172	$ 75,735	$ 200,171	$ 18,624	$ 961,143	$ 1,279,975

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to its employees. The Company's contributions for 2014 were $3,287 (2013 - $2,437).

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

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

(a) Net pension and OPEB obligation

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

	Pension benefits		OPEB	
	2014	2013	2014	2013
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 178,113**	$ 104,291	**$ 45,399**	$ 31,674
Projected benefit obligation assumed from business combination	**1,022**	73,601	**—**	17,943
Modifications to pension plan	**(560)**	81	**—**	—
Service cost	**4,828**	3,273	**2,022**	1,602
Interest cost	**8,549**	4,350	**2,186**	1,508
Actuarial loss (gain)	**39,704**	(11,395)	**14,893**	(8,499)
Benefits paid	**(8,125)**	(3,597)	**(1,255)**	(1,158)
Loss on foreign exchange	**18,432**	7,509	**5,012**	2,329
Projected benefit obligation, end of year	**$ 241,963**	$ 178,113	**$ 68,257**	$ 45,399
Change in plan asset				
Fair value of plan assets, beginning of year	**139,280**	66,524	**13,395**	10,195
Plan assets acquired in business combination	**—**	57,285	**—**	658
Actual return on plan assets	**6,568**	10,733	**1,176**	1,730
Employer contributions	**5,676**	3,013	**(222)**	1,208
Benefits paid	**(7,414)**	(3,597)	**(1,255)**	(1,157)
Gain on foreign exchange	**12,880**	5,322	**1,201**	761
Fair value of plan assets, end of year	**$ 156,990**	$ 139,280	**$ 14,295**	$ 13,395
Unfunded status	**$ (84,973)**	$ (38,833)	**$ (53,962)**	$ (32,004)
Amounts recognized in the consolidated balance sheets consists of:				
Current liabilities	**—**	(305)	**(333)**	—
Non-current liabilities	**(84,973)**	(38,528)	**(53,629)**	(32,004)
Net amount recognized	**$ (84,973)**	$ (38,833)	**$ (53,962)**	$ (32,004)

The accumulated benefit obligation for the pension plans was $219,007 and $162,179 as of December 31, 2014 and 2013, respectively.

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

(a) Net pension and OPEB obligation (continued)

The amounts recognized in AOCI before tax were as follows:

	AOCI	
	Pension	OPEB
Balance, January 1, 2013	$ 3,333	$ 821
Current year net actuarial gain	(17,777)	(9,878)
Current year prior service loss	82	—
Amortization of net actuarial loss	(23)	(26)
Balance at December 31, 2013	$ (14,385)	$ (9,083)
Current year net actuarial loss	43,350	14,338
Current year prior service credit	(563)	—
Amortization of net actuarial gain	349	641
Balance at December 31, 2014	$ 28,751	$ 5,896

The net actuarial loss for the defined benefit pension plans and OPEB that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $1,074 and $356, respectively.

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2014 and 2013 were as follows:

	Pension benefits		OPEB	
	2014	2013	2014	2013
Discount rate	**4.55%**	3.68%	**4.60%**	3.69%
Expected return on assets	**7.00%**	5.51%	**5.53%**	5.18%
Rate of compensation increase	**2.97%**	3.13%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.63%**	7.68%
Age 65 and after			**7.63%**	7.68%
Assumed Ultimate Medical Inflation Rate			**5.00%**	4.80%
Year in which Ultimate Rate is reached			**2019**	2019

Weighted average assumptions used to determine net benefit obligation for 2014 and 2013 were as follows:

	Pension benefits		OPEB	
	2014	2013	2014	2013
Discount rate	**3.71%**	4.55%	**3.80%**	4.60%
Rate of compensation increase	**3.01%**	2.97%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.00%**	7.63%
Age 65 and after			**7.00%**	7.63%
Assumed Ultimate Medical Inflation Rate			**5.00%**	5.00%
Year in which Ultimate Rate is reached			**2019**	2019

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

(b) Assumptions (continued)

The Company used the new mortality tables (RP-2014) and the mortality improvement scale (MP-2014) that were recently released by the Society of Actuaries in the current year assumptions. This change resulted in an increase to the pension and OPEB obligations of approximately U.S. $16,500.

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 2014 is as follows:

		2014
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	$	10,998
Total service and interest cost		623
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	$	(8,664)
Total service and interest cost		(503)

(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	
	2014	2013	2014	2013
Service cost	**$ 4,828**	$ 3,273	**$ 2,022**	$ 1,602
Interest cost	**8,549**	4,350	**2,186**	1,508
Expected return on plan assets	**(10,018)**	(4,160)	**(628)**	(602)
Amortization of net actuarial loss (gain)	**(346)**	23	**(641)**	26
Net benefit cost	**$ 3,013**	$ 3,486	**$ 2,939**	$ 2,534

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	74%	49.7%-78%
Debt securities	26%	21.9%-50.3%
Other	—%	0%-0.5%

The fair values of investments as of December 31, 2014, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	122,943	72%
Debt securities	47,771	28%
Other	570	—%

As of December 31, 2014, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $4,289 to its pension plans and $2,021 to its post-employment benefit plans in 2015.

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

	2015	2016	2017	2018	2019	2020-2024
Pension plan	$ 9,933	$ 10,471	$ 11,099	$ 11,709	$ 12,234	$ 69,107
OPEB	2,157	2,416	2,697	2,908	3,060	19,472

11. Mandatorily redeemable Series C preferred shares

Effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of the Company and the legal owner of the St. Leon Wind Facility (note 18). 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 detailed below. As these shares are mandatorily redeemable for cash, they are accounted for as liabilities in the consolidated financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units. 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.

The Series C preferred shares were initially measured at their estimated fair value of $18,497 based on the present value of the expected contractual cash flows including dividends and redemption amount, discounted at a rate of 5.0%. The recognition of the initial fair value of $18,497 resulted in an adjustment to equity of the shareholders of the Company as the Class B limited partnership units had a nominal carrying amount prior to the exchange. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

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

2015	$	1,077
2016		946
2017		895
2018		1,125
2019		1,334
Thereafter to 2031		19,525
Redemption amount		5,340
		30,242
Less amounts representing interest		(11,549)
		18,693
Less current portion		(1,085)
	$	17,608

12. Other assets

Other assets consist of the following:

	2014	2013
Restricted cash	**$ 18,702**	$ 6,021
Deferred financing costs	**10,732**	9,011
Other	**5,666**	3,752
	$ 35,100	$ 18,784

13. Other long-term liabilities and Deferred credits

Other long-term liabilities consist of the following:

	2014	2013
Asset retirement obligation	**$ 13,884**	$ 9,508
Customer deposits	**11,713**	8,774
Provision for injury and damages	**1,173**	1,215
Deferred water rights inducement	**2,683**	2,764
Contingent consideration	**1,202**	1,102
Other	**12,445**	4,580
	43,100	27,943
Less current portion	**(9,873)**	(7,451)
	$ 33,227	$ 20,492

The asset retirement obligation mainly relates to legal requirements to: (i) remove wind farm 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 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 obligation of $2,570 (2013 - $1,651) for newly constructed renewable generation facilities.

Deferred credits consist of the following:

	2014	2013
Deferred tax credit (note 20)	**$ 19,130**	$ 24,893
Deferred insurance proceeds	**12,190**	—
Deferred revenue	**942**	—
	$ 32,262	$ 24,893
Less: current portion	**(18,638)**	(7,778)
	$ 13,624	$ 17,115

Insurance proceeds received for some renewable generation facilities under repairs are deferred until they are virtually certain of being realized.

14. Shareholders' capital

(a) Common shares

Number of common shares:

	2014	2013
Common shares, beginning of year	**206,348,985**	188,763,486
Public offering (i)	**29,444,000**	—
Conversion and redemption of convertible debentures (ii)	**—**	150,816
Conversion of subscription receipts (iii)	**—**	15,223,016
Issuance of shares under the dividend reinvestment (iv) and employee share purchase plans ((c)(ii))	**2,356,483**	2,211,667
Common shares, end of year	**238,149,468**	206,348,985

14. Shareholders' capital (continued)

(a) Common shares (continued)

Authorized

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

On April 23, 2013, the Company's shareholders renewed its shareholders' rights plan (the "Rights Plan"). The Rights Plan has a term of three years. 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 2014, APUC issued 10,055,000 common shares at $9.95 per share pursuant to a public offering for proceeds of $100,047, before issuance costs of $4,243 or $3,021 net of taxes.

In September 2014, APUC issued 19,389,000 common shares at $8.90 per share pursuant to a public offering for proceeds of $172,562, before issuance costs of $7,648 or $5,719 net of taxes.

(ii) Conversion and redemption of convertible debentures

In 2013, $960 of Series 3 Debentures were redeemed for 150,816 common shares of APUC.

(iii) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 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 acquisition (note 8(a)). At any time after the earlier of commencement of operations of the Odell Wind Project or November 14, 2015, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by November 14, 2016, they will automatically convert into common shares.

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(b)). At any time after the earlier of the Park Water System acquisition or December 29, 2015, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by December 29, 2016, they will automatically convert into common shares.

On March 26, 2013, in connection with the acquisition of the Peach State Gas system, the Company issued 3,960,000 common shares at a price of $7.40 per share for total proceeds of $29,304 pursuant to a subscription receipt agreement with Emera.

On February 14, 2013, 11,263,016 subscription receipts issued in 2012 were exercised by Emera and the Company issued 11,263,016 common shares in exchange.

14. Shareholders' capital (continued)

(a) Common shares (continued)

(iv) 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 706,680 common shares under the dividend reinvestment plan.

(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. On November 9, 2012, APUC issued 4,800,000 Series A preferred shares, at a price of $25 per share, for aggregate proceeds of $120,000 before issuance cost of $4,700 or $3,454 net of tax.

The holders of preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.125 per share, payable quarterly, as and when declared by the Board. The Series A preferred shares yield 4.5% annually for the initial six-year period up to, but excluding December 31, 2018, with the first dividend payment occurring December 31, 2012. The dividend rate will reset on December 31, 2018, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018, and on December 31 of every fifth year thereafter. The holders of Series A preferred shares have the right to convert their shares into Cumulative Floating Rate preferred shares, Series B (the "Series B preferred shares"), subject to certain conditions, on December 31, 2018, and on December 31 of every fifth year thereafter. The Series B preferred shares carry the same features as the Series A preferred shares, except that holders 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%. The holders of Series B preferred shares will have the right to convert their shares back into Series A preferred shares on December 31, 2018, and on December 31 of every fifth year thereafter. The Series A preferred shares and the Series B preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St Leon LP. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets (note 11).

On March 5, 2014, APUC issued 4,000,000 Series D preferred shares, at a price of $25 per share, for aggregate proceeds of $100,000 before issuance costs of $3,729 or $2,741 net of tax.

The holders of the Series D preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.25 per share, payable quarterly, as and when declared by the Board. The Series D preferred shares yield 5.0% annually for the initial five-year period up to, but excluding March 31, 2019, with the first dividend payment occurring June 30, 2014. The dividend rate will reset on March 31, 2019, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D preferred shares are redeemable at $25 per share at the option of the Company on March 31, 2019, and on March 31 of every fifth year thereafter. The holders of Series D preferred shares have the right to convert their shares into Cumulative Floating Rate preferred shares, Series E (the "Series E preferred shares"), subject to certain conditions, on March 31, 2019, and on March 31 of every fifth year thereafter. The Series E preferred shares carry the same features as the Series D preferred shares, except that holders 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 3.28%. The holders of Series E preferred shares will have the right to convert their shares back into Series D preferred shares on March 31, 2019, and on March 31 of every fifth year thereafter. The Series D preferred shares and the Series E preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

14. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2014, APUC recorded $3,248 (2013 - $2,046) in total share-based compensation expense detailed as follows:

		2014		2013
Stock options	**$**	**1,931**	$	1,687
Directors deferred share units		**273**		155
Employee share purchase		**116**		75
Performance share units		**928**		129
Total share-based compensation	**$**	**3,248**	$	2,046

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, 2014, total unrecognized compensation costs related to non-vested options and performance share unit were $2,084 and $2,380, respectively, and are expected to be recognized over a period of 1.71 years and 1.61, respectively.

(i) Stock option plan

The Company's stock option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money" amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

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

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

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

	2014	2013
Risk-free interest rate	**1.97%**	1.61%
Expected volatility	**38%**	37%
Expected dividend yield	**3.84%**	3.83%
Expected life	**8 years**	8 years
Weighted average grant date fair value per option	**$ 2.00**	$ 2.00

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Stock option plan (continued)

Stock option activity during the period is as follows:

	Number of awards	Weighted average exercise price	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2013	3,750,727	$ 5.25	6.07	$ 5,939
Granted	816,402	7.72	8.00	—
Balance at December 31, 2013	4,567,129	$ 5.70	5.45	$ 7,814
Granted	969,998	7.95	8.00	—
Balance at December 31, 2014	5,537,127	$ 6.09	4.96	$ 19,648
Exercisable at December 31, 2014	3,601,647	$ 5.33	4.20	$ 15,531

(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, 2014, a total of 93,598 common shares (2013 - 85,410) 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, 2014, 110,241 (2013 - 74,786) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs.

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance share units

The Company offers a performance share unit 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 184% 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. During the second quarter, the Company settled 22,665 vested performance share units ("PSUs") for $162 in cash. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 common shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in common 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 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, 2013	83,483	$ 6.58	1.80	$ 571
Granted	5,537	6.79	1.23	41
Exercised	(20,640)	6.70	—	(151)
Forfeited	(2,185)	6.70	—	(16)
Balance at December 31, 2013	66,195	$ 6.57	0.62	$ 486
Granted, including dividends	407,962	8.22	3	3,333
Exercised	(22,665)	6.13	—	(185)
Forfeited	(11,406)	8.22	—	(93)
Balance at December 31, 2014	440,086	$ 6.57	1.81	$ 439
Exercisable at December 31, 2014	42,097	$ 6.86	—	$ 486

15. Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain (loss) on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2013	$ (105,957)	$ 3,596	$ —	$ (2,506)	$ (104,867)
OCI before reclassifications	48,486	10,357	—	16,698	75,541
Amounts reclassified	—	(2,113)	—	29	(2,084)
Net current period OCI	48,486	8,244	—	16,727	73,457
Balance, December 31, 2013	$ (57,471)	$ 11,840	$ —	$ 14,221	$ (31,410)
OCI (loss) before reclassifications	65,303	6,993	519	(35,396)	37,419
Amounts reclassified	—	5,423	(518)	(273)	4,632
Net current period OCI (loss)	$ 65,303	$ 12,416	$ 1	$ (35,669)	$ 42,051
Acquisition of non-controlling interest	21,029	2,543	—	—	23,572
Balance, December 31, 2014	$ 28,861	$ 26,799	$ 1	$ (21,448)	$ 34,213

Amounts reclassified from accumulated other comprehensive income (loss) 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.

16. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. For the year ended December 31, 2014, the Company declared dividends to shareholders on common shares totaling $82,898 (2013 - $68,291) or $0.3695 per common share (2013 - $0.3325 per common share). The Board declared a dividend on the Company's common shares of U.S. $0.0875 per share payable on January 15, 2015 to the shareholders of record on December 31, 2014.

For the year ended December 31, 2014, the Company declared and paid dividends to Series A preferred shareholders totaling $5,400 (2013 - $5,400) or $1.125 per Series A preferred share (2013 - $1.1250 per Series A preferred share).

For the year ended December 31, 2014, the Company declared and paid dividends to Series D preferred shareholders totaling $4,103 (2013 - $nil) or $1.0257 per Series D preferred share (2013 - $ nil per Series D preferred share).

17. Divestitures

(a) EFW Thermal Facility

During 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste Thermal Facility ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In 2013, the net assets of the EFW and BCI were written down to their estimated fair value less cost of sale, which resulted in a write-down of the net assets of $56,851 before tax, or $42,538 net of tax of $14,313. The Company sold the EFW and BCI Thermal Facilities on April 4, 2014. These assets were part of the Generation: Thermal reporting segment.

17. Divestitures (continued)

(b) Sale of U.S. Hydro facilities

On June 29, 2013, the Company sold 9 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company, for gross proceeds of U.S. $23,400 for a gain on sale of U.S. $960, net of tax recovery of U.S. $1,605. On June 16, 2014, the Company sold its final small U.S. hydroelectric generating facility for U.S. $3,600. These assets were part of the Generation: Renewable reporting segment.

(c) Results from discontinued operations

The assets of the EFW, BCI Thermal Facilities and the small U.S. hydroelectric generating facilities were presented as assets held for sale on the 2013 consolidated balance sheet and the operating results from these facilities are disclosed as discontinued operations in the 2014 and 2013 consolidated financial statements.

The summary of operating results and cash flows from discontinued operations for the years ended December 31 is as follows:

	2014	2013
Non-regulated energy sales	**$ 2,174**	$ 9,327
Waste disposal fees	**2,233**	8,160
Other and interest income	**63**	336
Operating and administrative expenses	**(5,284)**	(19,720)
Foreign exchange	**111**	80
Depreciation of property, plant and equipment	**—**	(2,483)
Interest expense	**(19)**	(58)
Gain (loss) on sale of assets	**(960)**	1,016
Write-off of assets	**(1,971)**	(57,160)
Non-cash gain on sale of assets	**105**	—
Deposit on sale	**143**	—
Loss from discontinued operations, before income taxes	**(3,405)**	(60,502)
Income tax recovery	**1,278**	18,491
Loss from discontinued operations, net of income taxes	**$ (2,127)**	$ (42,011)
Add:		
Depreciation of property, plant and equipment	**—**	2,483
Deposit on sale	**(143)**	—
Write-off of assets	**1,971**	57,160
Non-cash gain on sale of assets	**(105)**	—
Incurred closing costs on disposal of assets	**—**	(2,916)
Contingent liability	**—**	(613)
Income tax recovery	**(1,278)**	(18,491)
Cash used in discontinued operations	**$ (1,682)**	$ (4,388)

17. Divestitures (continued)

(c) Results from discontinued operations (continued)

Assets held-for-sale as of December 31, were as follows:

	2014	2013
Property, plant and equipment	$ —	$ 21,193
Accounts receivable and prepaid expenses	—	2,734
Total assets held for sale, current	$ —	$ 23,927

Liabilities held for sale as of December 31, were as follows:

	2014	2013
Accounts payable and accrued liabilities	$ —	$ 1,471

18. Related party transactions

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC, are indirect shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company and several related affiliates (collectively, the "Parties"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to the valuations of the generating assets, tax and legal matters.

The process initiated in 2011 was completed in November 2013 and all related party transactions except as noted below, between APUC and the Parties have been addressed to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

Due to and from related parties

Effective December 31, 2013, APUC paid the Parties $1,829 in connection with outstanding fees and the Parties paid APUC $812 in connection with reimbursement of expenses. As at December 31, 2014, $47 (2013 - $47) remains due from Algonquin Power Systems Ltd., a corporation partially owned by the Senior Executives.

Equity interests in Rattle Brook, Long Sault, BCI

The Parties owned interests in three power generation facilities in which APUC also has an interest in. A brief description of the facilities is provided as follows:

- Rattle Brook is a 4 MW hydroelectric generating facility ("Rattle Brook") constructed in 1998 in which APUC owned a 45% interest and Senior Executives hold an equity interest in the remaining 55%.
- Long Sault is an 18 MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in Long Sault by way of subscribing to two notes from the original partners. One of the original partners; an affiliate of APMI; was entitled to receive 5% of the equity cash flows commencing in 2014.
- Brampton Cogeneration is an energy supply facility which sells steam produced by EFW. In 2004, APMI acquired 50 Class B partnership units in BCI entitling them to 50% of the cash flow above 15% return on the investment.

18. Related party transactions (continued)

Equity interests in Rattle Brook, Long Sault, BCI (continued)

Effective December 31, 2013, APUC acquired the Parties' shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18 MW Long Sault Rapids hydroelectric facility and the partnership interest in the Brampton cogeneration plant for an amount equal to $3,780. As APUC already consolidates Long Sault as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10,692 in regards to tax attributes acquired with the partnership interests and an adjustment of $14,601 to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4 MW Rattle Brook hydroelectric facility to the Parties for gross proceeds $3,408 for a loss on sale, net of tax of $422.

APUC earned a fee of $400 from APC during the year ended December 31, 2013 related to settlement of the related party transactions.

St. Leon LP Units

Third-party investors, including Senior Executives previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership which is the legal owner of the St. Leon Wind Facility.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B limited partnership units (note 11) including 36 units held indirectly by Senior Executives. The Series C preferred shares provide dividends identical to what is expected from the Class B limited partnership units, as determined by independent consultants retained by the Independent Board Committee. As at January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2014 were $315 (2013 - $310). In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease for nominal consideration. There is no further related party matter in relation to an office lease.

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $472. As at December 31, 2013, the Independent Board Committee and the Parties agreed that all future utilization of chartered aircraft would be undertaken through a third-party charter operator at fair market value and under arrangements in which the Senior Executives have no interest. Final arrangements in this regard had not been completed as at December 31, 2014. During the year ended December 31, 2014, APUC reimbursed direct costs in connection with the use of the aircraft of $709.

Trafalgar

The Company owns 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 affiliate of APMI moved to foreclose on the assets. Subsequently Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2 million in legal fees prior to 2004.

In 2004, the Company reimbursed APMI $1 million of the total third-party legal fees (which to that point totalled $2 million), and APUC agreed to fund future legal fees, third-party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

18. Related party transactions (continued)

Other related party transactions

A member of the Board is an executive at Emera. Related party transactions between APUC and Emera are discussed below:

- For the year ended December 31, 2014, the Company sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $5,780 (2013 - U.S. $6,042). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S. $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine. For the year ended December 31, 2014, the Company purchased natural gas amounting to U.S. $5,006 (2013 - U.S. $1,304) 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.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1,000 to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. There has not been any transaction under this contract in the last three years.

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

Other

A spouse of one of the Senior Executives provided market research consulting services to certain subsidiaries of the Company. During the year ended December 31, 2014 APUC paid $192 (2013 - $45) in relation to these services.

19. Non-controlling interests

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

		2014		2013
Net earnings attributable to Class B partnership units of Wind Portfolio SponsorCo	**$**	**3,484**	$	9,556
Net loss attributable to Class A partnership units		**(27,199)**		(20,408)
Other net earnings attributable to non-controlling interests		**1,529**		39
Total net loss attributable to non-controlling interests	**$**	**(22,186)**	$	(10,813)

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

The non-controlling Class A membership equity investors ("Class A partnership units") of Wind Portfolio SponsorCo and of the Bakersfield Solar Project, beginning December 31, 2014 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(t).

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% (2013 - 26.5%). The differences are as follows:

		2014		2013
Expected income tax expense at Canadian statutory rate	**$**	**19,199**	$	16,072
Increase (decrease) resulting from:				
Recognition of deferred credit		**(5,763)**		(6,676)
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates		**(1,677)**		(2,338)
Non-taxable corporate dividend		**(2,618)**		(2,896)
Non-controlling interests share of income		**8,824**		4,266
Production tax credit		**(339)**		(247)
Allowance for equity funds used during construction		**(746)**		(694)
State taxes		**604**		313
Other		**(677)**		1,355
Income tax expense	**$**	**16,807**	$	9,155

For the years ended December 31, 2014 and 2013, earnings from continuing operations before income taxes consists of the following:

		2014		2013
Canadian operations	**$**	**11,930**	$	19,687
U.S. operations		**60,519**		40,962
	$	**72,449**	$	60,649

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

		Current		Deferred		Total
Year ended December 31, 2014						
Canada	$	5,660	$	(3,538)	$	2,122
United States		(1,986)		16,671		14,685
	$	3,674	$	13,133	$	16,807
Year ended December 31, 2013						
Canada	$	1,532	$	881	$	2,413
United States		994		5,748		6,742
	$	2,526	$	6,629	$	9,155

20. Income taxes (continued)

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, 2014 and 2013 are presented below:

	2014	2013
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 319,056**	$ 226,314
Pension and OPEB	**54,458**	31,433
Acquisition related costs	**5,168**	5,152
Environmental obligation	**28,555**	23,076
Production tax credit	**2,098**	1,633
Reserves not currently deductible	**2,315**	2,397
Other	**3,988**	2,780
Total deferred income tax assets	**415,638**	292,785
Less valuation allowance	**(15,534)**	(15,667)
Total deferred tax assets	**400,104**	277,118
Deferred tax liabilities:		
Property, plant and equipment	**(387,931)**	(267,344)
Intangible assets	**(2,752)**	(8,321)
Outside basis in partnership	**(15,194)**	(2,210)
Regulatory accounts	**(49,399)**	(24,745)
Financial derivatives	**(15,013)**	(7,675)
Total deferred tax liabilities	**(470,289)**	(310,295)
Net deferred tax liabilities	**$ (70,185)**	$ (33,177)

The valuation allowance for deferred tax assets as at December 31, 2014 was $ (15,534) (2013 - $(15,667)). 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 carry back and carry forward periods), projected future taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2014	2013
Current deferred income tax asset	**$ 7,210**	$ 19,652
Non-current deferred income tax asset	**57,065**	86,632
Current deferred income tax liability	**(3,702)**	(2,308)
Non-current deferred income tax liability	**(130,758)**	(137,153)
	$ (70,185)	$ (33,177)

20. Income taxes (continued)

As of December 31, 2014, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry		Non-capital loss carryforwards
2015	$	5,426
2016 and onwards		733,022
	$	738,448

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one-for-one basis for common shares of APUC (the "Unit Exchange Transaction"). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of $55,647 on the date of the Unit Exchange Transaction (the "Transaction Date"). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

Subsequent to the balance sheet date, APUC received a proposal letter from the Canada Revenue Agency ("CRA") which outlines its intention to challenge the tax consequences of the Unit Exchange Transaction. CRA is seeking to apply the acquisition of control rules or the general anti-avoidance rules of the Income Tax Act (Canada) the effect of which would be to deny APUC of the benefit of the tax attributes assumed as part of the Unit Exchange Transaction.

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17,500. Additionally, assuming 2014 return will be similarly reassessed, a further payment of approximately $3,100 would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar Notice of Reassessment for such years and APUC were to appeal it.

Should APUC be successful in defending its position, all such payments plus applicable interest, will be refunded to APUC. If the CRA is successful, APUC would be required to pay the balance of the taxes assessed, plus interest and penalties.

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from $nil to $45,000.

The impact of the proposal on APUC's tax provision has been considered by management; however, management continues to believe that the most likely outcome has not changed and it is more likely than not, that APUC will be successful in defending its position. On this basis, APUC's 2014 financial statements do not include the impact of a potential reassessment. Until the matter is resolved with CRA, or should new facts arise that would result in a change to management's assessment of the most likely outcome, any future deposit tax payments made by APUC will be recorded to the consolidated balance sheets and will not impact net earnings.

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 outstanding and subscription receipts issued (note 14 (a)(iii)) during the year. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts issued, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the period and, if dilutive, potential incremental common shares issuable upon the exercise of stock options. The dilutive effect of outstanding stock options is reflected in diluted earnings per share by application of the treasury stock method.

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:

		2014		2013
Net earnings attributable to shareholders of APUC	**$**	**75,701**	$	20,296
Series A Preferred shares dividend		**5,400**		5,400
Series D Preferred shares dividend		**4,103**		—
Net earnings attributable to common shareholders of APUC	**$**	**66,198**	$	14,896
Discontinued operations		**(2,127)**		(42,011)
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	**$**	**68,325**	$	56,907
Weighted average number of shares				
Basic		**213,953,870**		204,350,689
Effect of dilutive securities		**2,387,722**		1,482,515
Diluted		**216,341,592**		205,833,204

The shares potentially issuable as a result of 1,786,401 stock options (2013 – 885,418) are excluded from this calculation as they are anti-dilutive.

22. Segmented information

During the fourth quarter, the Company aligned its management reporting under three business units - Generation, Transmission and Distribution. As a result, APUC has four reporting segments. Under Generation, the Company owns or has interests in hydroelectric, solar and wind power facilities which are aggregated as the renewable segment and operates co-generation, steam production and other thermal facilities which are aggregated as the thermal segment. The Distribution reporting segment now aggregates the electric, natural gas and water distribution utilities into a single reporting segment. Finally, the Transmission reporting segment, invests in rate regulated electric transmission and natural gas pipeline systems.

The operating segments were aggregated as generation (renewable, thermal), distribution and transmission based on their economic characteristics. The Transmission segment includes the new equity method investment in the Natural Gas Pipeline Development (note 8(b)) which is not yet significant and as a result is not presented separately in the tables below.

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 new segments are reflected in the tables below. The comparative information for 2013 has been reclassified to conform with the composition of the reporting segments presented in the current year.

22. Segmented information (continued)

	Year ended December 31, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 206,667	$ —	$ 206,667
Regulated gas distribution	—	—	—	446,025	—	446,025
Regulated water reclamation and distribution	—	—	—	66,419	—	66,419
Non-regulated energy sales	159,400	42,900	202,300	—	—	202,300
Other revenue	13,257	3,208	16,465	5,684	—	22,149
Total revenue	172,657	46,108	218,765	724,795	—	943,560
Operating expenses	46,077	9,405	55,482	180,442	60	235,984
Regulated electricity purchased	—	—	—	120,506	—	120,506
Regulated gas purchased	—	—	—	261,116	—	261,116
Non-regulated energy purchased	16,676	22,588	39,264	—	—	39,264
	109,904	14,115	124,019	162,731	(60)	286,690
Administrative expenses	(13,120)	(337)	(13,457)	(19,947)	(1,288)	(34,692)
Depreciation of property, plant and equipment	(48,479)	(5,980)	(54,459)	(52,387)	(2,128)	(108,974)
Amortization of intangible assets	(2,979)	(891)	(3,870)	(756)	—	(4,626)
Other amortization	81	—	81	(528)	—	(447)
Gain on foreign exchange	—	—	—	—	1,112	1,112
Interest expense	(32,117)	(1,751)	(33,868)	(27,139)	(1,411)	(62,418)
Interest, dividend income and other income	1,683	(496)	1,187	3,369	3,202	7,758
Gain on sale of asset	110	326	436	—		436
Acquisition-related costs	—	—	—	—	(2,552)	(2,552)
Write-down of long-lived assets	—	(698)	(698)	(300)	(7,465)	(8,463)
Gain (loss) on derivative financial instruments	214	—	214	—	(1,589)	(1,375)
Earnings from continuing operations before income taxes	15,297	4,288	19,585	65,043	(12,179)	72,449
Loss from discontinued operations before income taxes	(3,189)	(216)	(3,405)	—	—	(3,405)
Earnings (loss) before income taxes	$ 12,108	$ 4,072	$ 16,180	$ 65,043	$ (12,179)	$ 69,044
Property, plant and equipment	$ 1,602,465	$ 85,000	$ 1,687,465	$ 1,531,166	$ 59,791	$ 3,278,422
Equity-method investees	2,267	1,253	3,520	1,563	1,652	6,735
Total assets	1,795,757	100,603	1,896,360	2,106,638	111,417	4,114,415
Capital expenditures	197,051	4,012	201,063	176,849	54,461	432,373
Acquisition of operating entities	—	—	—	8,757	—	8,757

22. Segmented information (continued)

	Year ended December 31, 2013					
	Generation			Distribution	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 166,156	$ —	$ 166,156
Regulated gas distribution	—	—	—	260,424	—	260,424
Regulated water reclamation and distribution	—	—	—	57,350	—	57,350
Non-regulated energy sales	145,661	34,530	180,191	—	—	180,191
Other revenue	7,058	2,442	9,500	1,270	400	11,170
Total revenue	152,719	36,972	189,691	485,200	400	675,291
Operating expenses	40,282	8,514	48,796	131,550	—	180,346
Regulated electricity purchased	—	—	—	97,376	—	97,376
Regulated gas purchased	—	—	—	148,784	—	148,784
Non-regulated energy purchased	8,684	17,151	25,835	—	—	25,835
	103,753	11,307	115,060	107,490	400	222,950
Administrative expenses	(13,094)	(223)	(13,317)	(7,477)	(2,724)	(23,518)
Depreciation of property, plant and equipment	(45,122)	(5,439)	(50,561)	(41,417)	—	(91,978)
Amortization of intangible assets	(2,652)	(856)	(3,508)	(692)	—	(4,200)
Other amortization	81	—	81	78	—	159
Gain on foreign exchange	—	—	—	—	567	567
Interest expense	(27,472)	(1,046)	(28,518)	(23,734)	(1,174)	(53,426)
Interest, dividend income and other income	1,867	193	2,060	3,228	2,497	7,785
Loss on sale of asset	(750)	—	(750)	—	—	(750)
Acquisition-related costs	—	—	—	—	(2,140)	(2,140)
Gain (loss) on derivative financial instruments	(767)	—	(767)	—	5,967	5,200
Earnings from continuing operations before income taxes	15,844	3,936	19,780	37,476	3,393	60,649
Loss from discontinued operations before income taxes	1,128	(61,630)	(60,502)	—	—	(60,502)
Earnings (loss) before income taxes	$ 16,972	$ (57,694)	$ (40,722)	$ 37,476	$ 3,393	$ 147
Property, plant and equipment	$ 1,364,843	$ 79,828	$ 1,444,671	$ 1,264,033	$ —	$ 2,708,704
Equity-method investees	—	1,718	1,718	325	8,623	10,666
Total assets	1,492,144	116,922	1,609,066	1,673,631	193,784	3,476,481
Capital expenditures	46,885	2,631	49,516	108,861	—	158,377
Acquisition of operating entities	2,083	—	2,083	236,931	—	239,014

22. Segmented information (continued)

Operational segments (continued)

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 2014 or 2013: Hydro Québec 11% (2013 - 14%) and Manitoba Hydro 13% (2013 - 14%). 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:

		2014		2013
Revenue				
Canada	**$**	**92,267**	$	65,380
United States		**851,293**		609,911
	$	**943,560**	$	675,291
Property, plant and equipment				
Canada	**$**	**590,580**	$	433,153
United States		**2,687,842**		2,275,551
	$	**3,278,422**	$	2,708,704
Intangible assets				
Canada	**$**	**25,601**	$	26,802
United States		**28,410**		27,614
	$	**54,011**	$	54,416

Revenues are 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, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

(i) On October 21, 2011, the Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the Government of Quebec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,400. In 2012, the Company paid an amount of $1,884 to the government of Quebec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

23. Commitments and contingencies (continued)

(a) Contingencies (continued)

(ii) The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services and the Massachusetts Department of Environmental Protection.

Like most other industrial companies, the gas and electric distribution utilities generate some hazardous wastes. Under federal and state laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities, these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by the 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 believes that obligations imposed on it because of those sites will not have a material impact on its results of operations.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $72,594 which at discount rates ranging from 2.1% to 3.4% represents the recorded accrual of $72,305 as of December 31, 2014 (December 31, 2013 - $69,555).

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, 2014, the Company has reflected a regulatory asset of $102,735 (December 31, 2013 - $85,029) for the MGP and related sites (note 7(a)).

Estimated cash flows for site investigation and remediation costs in the next five years and thereafter are as follows:

2015	$	19,643
2016		22,229
2017		14,394
2018		5,443
2019		629
Thereafter to 2046		10,256
	$	72,594

(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, 2014.

As a result of the dam safety legislation passed in Quebec (Bill C-93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $7,900 over a period of five years related to compliance with the legislation.

23. Commitments and contingencies (continued)

(b) Commitments (continued)

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
Purchased power	$ 118,158	$ —	$ —	$ —	$ —	$ —	$ 118,158
Gas delivery, service and supply agreements	52,848	37,714	30,318	27,718	27,625	88,234	264,457
Service agreements	28,572	32,147	32,537	31,556	31,382	481,061	637,255
Capital projects	21,972	—	—	—	—	—	21,972
Operating leases	5,647	4,951	4,604	4,274	4,190	97,421	121,087
Total	$ 227,197	$ 74,812	$ 67,459	$ 63,548	$ 63,197	$ 666,716	$ 1,162,929

Calpeco Electric System has entered into a five-year all-purpose power purchase agreement with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five-year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2014. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State Electric System has several types of contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

24. Non-cash operating items

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

	2014	2013
Accounts receivable	**$ 2,572**	$ (213)
Prepaid expenses	**36**	(11)
Accrued liabilities	**(1,346)**	260
	$ 1,262	$ 36

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

	2014	2013
Accounts receivable	**$ (23,640)**	$ (49,888)
Related party balances	**—**	(996)
Natural gas in storage	**(5,942)**	(6,330)
Supplies and consumable inventory	**(3,861)**	(525)
Income taxes receivable	**(189)**	177
Prepaid expenses	**827**	(485)
Accounts payable	**54,299**	(29,292)
Accrued liabilities	**32,520**	37,023
Current income tax liability	**(1,527)**	1,399
Net regulatory assets and liabilities	**(54,277)**	1,098
	$ (1,790)	$ (47,819)

25. Financial instruments

(a) Fair value of financial instruments

2014	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 39,510	$ 41,339	$ —	$ 41,339	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	41,966	41,966	—	—	41,966
Energy contracts not designated as a cash flow hedge	504	504	—	—	504
Total derivative financial instruments	42,470	42,470	—	—	42,470
Total financial assets	$ 81,980	$ 83,809	$ —	$ 41,339	$ 42,470
Long-term liabilities	$ 1,280,023	$ 1,363,934	$ 520,142	$ 843,792	$ —
Preferred shares, Series C	18,693	18,209	—	18,209	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	36,276	36,276	—	36,276	—
Interest rate swap designated as a hedge	4,684	4,684	—	4,684	—
Interest rate swaps not designated as a hedge	1,383	1,383	—	1,383	—
Commodity contracts for regulated operations	2,928	2,928	—	2,928	—
Total derivative financial instruments	45,271	45,271	—	45,271	—
Total financial liabilities	$ 1,343,987	$ 1,427,414	$ 520,142	$ 907,272	$ —

25. Financial instruments (continued)

(a)Fair value of financial instruments (continued)

2013	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,678	$ 26,321	$ —	$ 26,321	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	31,971	31,971	—	—	31,971
Energy contracts not designated as a cash flow hedge	3,737	3,737	—	—	3,737
Cross-currency swap designated as a net investment hedge	109	109	—	109	—
Commodity contracts for regulatory operations	482	482	—	482	—
Total derivative financial instruments	36,299	36,299	—	591	35,708
Total financial assets	$ 58,977	$ 62,620	$ —	$ 26,912	$ 35,708
Long-term liabilities	$ 1,255,588	$ 1,261,340	$ 296,986	$ 964,354	$ —
Preferred shares, Series C	18,805	18,293		18,293	—
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	4,781	4,781	—	—	4,781
Cross-currency swap designated as a net investment hedge	7,947	7,947	—	7,947	—
Interest rate swaps not designated as a hedge	3,180	3,180	—	3,180	—
Commodity contracts for regulated operations	313	313	—	313	—
Total derivative financial instruments	16,221	16,221	—	11,440	4,781
Total financial liabilities	$ 1,290,614	$ 1,295,854	$ 296,986	$ 994,087	$ 4,781

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, 2014 and 2013 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 liabilities 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 Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 9.0%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $nil during the years ended December 31, 2014 or 2013.

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 $16.62 to $113.93 with a weighted average of $39.72 as of December 31, 2014. 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 are 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, 2014 or 2013.

25. Financial instruments (continued)

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value 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 sales prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

	2014
Financial contracts: Gas swaps	1,774,018
Gas options	907,758
	2,681,776

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(d)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact. 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:

	2014		2013	
Regulatory assets:				
Gas swap contracts	U.S. **$**	**2,178**	U.S. $	86
Gas option contracts	U.S. **$**	**346**	U.S. $	208
Regulatory liabilities:				
Gas swap contracts	U.S. **$**	**—**	U.S. $	416
Gas option contracts	U.S. **$**	**—**	U.S. $	37

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities and at one of its hydro facilities no longer subject to a power purchase agreement by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Pay floating price (per MW-hr)
98,167	December 2016	$	67.91	AESO
915,428	December 2022	U.S. $	42.81	PJM Western HUB
3,907,711	December 2022	U.S. $	30.25	NI HUB
4,330,303	December 2027	U.S. $	36.46	ERCOT North HUB

On November 14, 2014, the Company entered into a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a loss of $4,684 for the year ended December 31, 2014, which is recorded in OCI.

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

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

	2014	2013
Effective portion of cash flow hedge, loss	**$ 1,043**	$ 18,940
Amortization on cash flow hedge	**(32)**	(30)
Loss (gain) reclassified from AOCI into non-regulated energy sales	**5,423**	(1,602)
	$ 6,434	$ 17,308
Less non-controlling interest	**5,982**	(9,064)
Change in OCI attributable to shareholders of APUC	**$ 12,416**	$ 8,244

The Company expects $10,132 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.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. 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.

Concurrent with its $150,000 and $200,000 debenture offerings in December 2012 and January 2014, 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 loss of $28,537 (2013 - loss of $5,771) was recorded in OCI in 2014.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Assets 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.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Net Asset
18,283	March 2015	U.S. $	57.53	$ 417

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $60,513 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. As of December 31, 2014, the estimated fair value of the interest rate swap was a liability of $1,383 (2013 – liability of $3,180). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

For derivatives that are not designated as cash flow 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:

		2014		2013
Change in unrealized loss (gain) on derivative financial instruments:				
Interest rate swaps	**$**	**(1,797)**	$	(1,598)
Energy derivative contracts		**3,386**		(3,809)
Total change in unrealized loss (gain) on derivative financial instruments	**$**	**1,589**	$	(5,407)
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps		**1,962**		2,024
Energy derivative contracts		**(3,627)**		(466)
Total realized loss (gain) on derivative financial instruments	**$**	**(1,665)**	$	1,558
Gain on derivative financial instruments not accounted for as hedges		**(76)**		(3,849)
Ineffective portion of derivative financial instruments accounted for as hedges		**1,451**		(1,351)
Loss (gain) on derivative financial instruments	**$**	**1,375**	$	(5,200)

(c) Risk management

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

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

25. Financial instruments (continued)

(c) Risk management (continued)

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 in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with 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 Distribution Group which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Distribution Group accounts receivable balances of U.S. $119,866 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 Distribution Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2014, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2014	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 5,823	$ 19,095
Accounts receivable	20,320	151,265
Allowance for doubtful accounts	—	(6,232)
Notes receivable	21,901	15,179
	$ 48,044	$ 179,307

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 our 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.

As of December 31, 2014, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $156 (2013 - $7,344) was held as collateral by the counterparty.

25. Financial instruments (continued)

(c) Risk management (continued)

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, 2014, in addition to cash on hand of $9,273 the Company had $485,927 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.

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	$ 9,130	$ 90,955	$ 218,795	$ 961,143	$ 1,280,023
Advances in aid of construction	1,149	—	—	79,955	81,104
Interest on long-term debt	64,232	125,268	102,070	146,689	438,259
Purchase obligations	267,914				267,914
Environmental obligation	19,643	36,623	6,072	10,256	72,594
Derivative financial instruments:					
Cross-currency swap	1,463	2,975	2,433	29,405	36,276
Interest rate forwards	—	—	4,684	—	4,684
Interest rate swaps	1,383	—	—	—	1,383
Energy derivative and commodity contracts	2,337	591	—	—	2,928
Other obligations	9,873	860	25	29,659	40,417
Total obligations	$ 377,124	$ 257,272	$ 334,079	$ 1,257,107	$ 2,225,582

Foreign currency risk

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.

The Company designates the amounts drawn on the Generation Group's revolving credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of the facility that is designated as a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in OCI) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $2,727 for the year-ended December 31, 2014 (2013 - $1,607) was recorded in OCI.

Interest rate risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, 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 does not currently hedge that risk.

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

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, 2014. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2014 and 2013. 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 15, 2015.

Caution concerning forward-looking statements and non-GAAP Measures

Forward-looking statements

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

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

Non-GAAP Financial Measures

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

Use of Non-GAAP Financial Measures

Adjusted EBITDA

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

Adjusted net earnings

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

Adjusted funds from operations

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

Net energy sales

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

Net utility sales

Net utility sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodities are generally included as a pass through in rates to its utility customers. APUC uses net utility sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of net utility sales on this

basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is U.S. $0.0875 per share or U.S. $0.35 per share per annum. Based on exchange rates as at December 31, 2014, the quarterly dividend is equivalent to CAD $0.10 per share or CAD $0.41 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

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

Generation Business Group

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

The Generation Group owns or has interests in hydroelectric, wind, and solar facilities with a combined generating capacity of approximately 120 MW, 675 MW, and 10MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group owns or has interests in thermal energy facilities with approximately 335 MW of installed generating capacity. Approximately 91% of the electrical output from the owned thermal facilities is sold pursuant to long term power purchase agreements ("PPA") with major utilities, which have a weighted average remaining contract life of 7 years.

The Generation Group also has a portfolio of development projects that between 2015 and 2018 will add approximately 529 MW of generation capacity from wind and solar powered generating stations with an average contract life of 22 years.

Distribution Business Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 488,000 connections. The Distribution Group provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

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

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

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together serve approximately 103,000 connections.

Transmission Business Group

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

Major Highlights

2014 Corporate Highlights

Dividend Increased to U.S. $0.35 Per Common Share Annually

APUC has completed several acquisitions and advanced on other initiatives including its power development projects that have raised the growth profile for APUC's earnings and cash flows which in turn supports an increase in the dividend to shareholders. As a result, 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 per annum, 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. APUC's consolidated assets are approximately 80% based in the U.S. and generate approximately 77% of its underlying cash flows.

Management believes that the increase in dividend is consistent with APUC's stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Strengthening the Balance Sheet and Poising for Continued Growth

Issuance of $100 million Preferred Shares

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D at a price of $25 per share, for aggregate gross proceeds of $100.0 million. The Series D shares will 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 revolving credit facilities, and for general corporate purposes.

Issuance of Common Shares

On September 16, 2014, APUC completed a public offering (the "September 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 Offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the September Offering. As a result, APUC issued an aggregate of 19,389,000 common shares under the September 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 revolving credit facilities, and for general corporate purposes.

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 ("Subscription Receipts") of APUC at a price of $8.90 per Subscription Receipt, for a subscription price of $70.0 million.

On September 26, 2014, as a result of the Underwriters exercising the Over-Allotment Option, an additional 843,000 Subscription Receipts were issued to Emera at a price of $8.90 per Subscription Receipt, for an aggregate subscription price 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 a subscription price of $33.0 million.

The proceeds of the Subscription Receipts private placements are intended to be used to partially finance the acquisitions of the Odell Wind Project and the Park Water Facility (described below).

2014 Generation Group Highlights

Acquisition of Odell Wind Project

On September 4, 2014, the Generation Group announced an opportunity to acquire an interest in the Odell Wind Project, of Minnesota. The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and renewable energy credits 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 is expected to begin in the second quarter of 2015, with total costs estimated at U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in late 2015 or early 2016.

Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Generation Group completed the construction of its 10 MWac solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014 for a total capital cost of approximately $47.6 million. The facility represents the first solar project in the 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 FIT PPA with the Ontario Power Authority.

Completion of St. Damase Wind Project

On December 2, 2014, the first phase of the wind facility located in the local municipality of St. Damase 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 Quebec.

It is expected that the turbines and other components utilized in the first 24 MW phase of the St. Damase Wind Project will qualify as Canadian Renewable and Conservation Expense ("CRCE"), and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec tax credit ("Quebec CRCE Tax Credit"). The estimated value of the Quebec CRCE tax credit for the St. Damase project is expected to be approximately $16.6 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.

Significant Progress on Power Development Projects

During 2014, the Generation Group made significant progress advancing several of its development projects. Construction on the Bakersfield I Solar Project near Bakersfield, California began in the second quarter of 2014 and was placed in service on December 30, 2014. Final construction efforts continue with the project expected to reach full commercial operations in the first quarter of 2015.

Construction of the Morse Wind Project near Morse, Saskatchewan is in its final stages. Installation of access roads and foundations are complete, turbine delivery commenced in January 2015, and seven of ten turbines have been erected. The project is expected to be operational by March 31, 2015.

Expansion of Bakersfield I Solar Project

On November 24, 2014, APUC announced that it intends to proceed with a 10 MW project adjacent to its 20MW Bakersfield I Solar project in Kern County, California, which is currently under construction.

The 10MW Bakersfield II Solar project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20MW Bakersfield I Solar project. Construction of Bakersfield I Solar is nearing completion, with commercial operations expected to occur in the first quarter of 2015.

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

Acquisition of the Remaining 40% of a 400 MW Wind Power Portfolio

On March 31, 2014, the 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 power portfolio (the “U.S. Wind Portfolio”)

in the United States for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Generation Group now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio.

The Generation Group originally acquired 60% of the Class B units of the entity which owns the U.S. Wind Portfolio in 2012. The U.S. Wind Portfolio is a 400 MW wind portfolio consisting of three facilities: Minonk (200MW), Senate (150MW), and Sandy Ridge (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts.

$200 million Senior Unsecured Debentures

On January 17, 2014, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "Generation Group Debentures") pursuant to a private placement in Canada and the United States. The 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 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 the Generation Group's senior unsecured revolving credit facility ("Generation Credit Facility"), and for general corporate purposes.

Additional Liquidity

On July 31, 2014, the Generation Group increased the credit available under the Generation Credit Facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018.

2014 Distribution Group Highlights

Agreement to acquire Park Water System

On September 19, 2014, the Distribution 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 (“Park Water System”). 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 is expected to be approximately U.S. $327 million, which includes the assumption of approximately U.S. $77 million of existing long-term utility debt. The acquisition will maintain APUC’s strategic business mix and further enhance its investment grade consolidated capital structure.

Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4.5 million.

Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. $3.0 million, subject to certain closing adjustments.

Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure appropriate return on the rate base at its various utility systems. The group has successfully completed several rate cases throughout 2014, representing a cumulative annual revenue increase of approximately U.S. $29.1 million. The full annualized impact of these rate cases will be realized in 2015. Further detail on the various regulatory proceedings of the Distribution Group can be found under Regulatory Proceedings.

2014 Transmission Group Highlights

Agreement to acquire interest in Natural Gas Transmission Pipeline

On November 24, 2014, APUC announced its agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. “A,” a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts(the “Project”), which will be operated by Tennessee Gas Pipeline Company, L.L.C. (“Tennessee”) . The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with commercial operations occurring by late 2018.

Under the agreement, APUC will initially subscribe for a 2.5% interest in Northeast Expansion LLC with an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. $400 million, depending on the final pipeline configuration and design capacity.

2014 Annual Results From Operations

As outlined, APUC has continued to advance growth initiatives throughout 2014 that had a positive contribution to the annual results. In addition, the results now reflect full year operations from the gas and water systems acquisitions completed by the Distribution Group in 2013.

Key Selected Annual Financial Information

(all dollar amounts in $ millions except per share information)	Year ended December 31 2014	2013	2012
Revenue	**$ 943.6**	$ 675.3	$ 348.8
Adjusted EBITDA [1]	**290.6**	228.1	88.1
Cash provided by operating activities	**192.7**	98.9	63.0
Adjusted funds from operations [1]	**206.5**	154.9	66.8
Net earnings attributable to Shareholders from continuing operations	**77.8**	62.3	13.5
Net earnings attributable to Shareholders	**75.7**	20.3	14.5
Adjusted net earnings [1]	**88.4**	59.5	18.9
Dividends declared to Common Shareholders	**82.9**	68.3	50.2
Weighted Average number of common shares outstanding	**213,953,870**	204,350,689	158,304,340
Per share			
Basic net earnings from continuing operations	**$ 0.32**	$ 0.28	$ 0.08
Basic net earnings	**$ 0.31**	$ 0.07	$ 0.09
Adjusted net earnings [1, 2]	**$ 0.37**	$ 0.26	$ 0.11
Diluted net earnings	**$ 0.31**	$ 0.07	$ 0.09
Cash provided by operating activities [1, 2]	**$ 0.90**	$ 0.48	$ 0.40
Adjusted funds from operations [1, 2]	**$ 0.92**	$ 0.73	$ 0.42
Dividends declared to Common Shareholders	**$ 0.37**	$ 0.33	$ 0.30
Total assets	**4,113.7**	3,476.5	2,779.0
Long term liabilities [3]	**1,280.0**	1,255.6	770.8

[1] Non-GAAP Financial Measures

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

[3] Includes long-term liabilities and current portion of long-term liabilities

For the year ended December 31, 2014, APUC experienced an average U.S. exchange rate of approximately $ 1.1049 as compared to $ 1.0300 in the same period in 2013. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the year ended December 31, 2014, APUC reported total revenue of $943.6 million as compared to $675.3 million during the same period in 2013, an increase of $268.3 million or 39.7%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

(all dollar amounts in $ millions)		Year to date December 31, 2014
Comparative Prior Period Revenue	$	675.3
Significant Changes:		
Generation Group		
Renewable:		
Increased wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities		1.1
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities		4.8
Start of commercial operations of the Cornwall Solar Facility		5.5
Increased customer load in the Maritime region		1.7
Thermal:		
Increased average prices at the Windsor Locks and Sanger Thermal Facilities		5.3
Increased sale of Renewable Energy Credits generated at the Windsor Locks Thermal Facility		0.7
Distribution Group		
Natural Gas Systems - Increased revenue due to acquisition of the Peach State Gas System (U.S. $32.9 million), and the New England Gas System (U.S. $76.3 million)		108.2
Natural Gas Systems - Revenue increase due to higher customer demand as a result of colder than average weather at the EnergyNorth and Midstates Natural Gas Systems		35.2
Electric Systems - Revenue increase at the electric systems predominantly due to higher customer demand at the Granite State Electric System		13.8
Rate Cases – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $11.8 million) and Peach State Gas System (U.S. $5.5 million)		17.2
Water and Waste Systems – Revenue increase due to the increased customer demand		3.5
Increase due to acquisition of New England Gas System's water heater rental service (U.S. $2.8 million) and increased revenues at Peach State Gas System's Fort Benning operation (U.S. $1.0 million)		3.8
Impact of the stronger U.S. dollar		68.4
Other		(0.9)
Current Period Revenue	$	943.6

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

Adjusted EBITDA in the year ended December 31, 2014 totalled $290.6 million as compared to $228.1 million during the same period in 2013, an increase of $62.5 million or 27.4%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2014 and 2013, impact of rate case settlements, increased customer demand for Gas distribution, and the increase in REC transactions. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2014, net earnings from continuing operations attributable to Shareholders totalled $77.8 million as compared to $62.3 million during the same period in 2013, an increase of $15.5 million. The increase was due to $63.7 million in increased earnings from operating facilities, $0.5 million in increased foreign exchange gains, and $1.2 million due to a gain on sale of assets, as compared to the same period in 2013. These items were partially offset by $18.0 million in increased depreciation and amortization expenses, $11.2 million in increased administration charges, $9.0 million in increased interest expense, $0.4 million in increased acquisition costs, $8.5 million in increased write-downs on notes receivable and property, plant, and equipment, $6.6 million in increased loss from derivative instruments, $11.4 million in increased allocations of earnings to non-controlling interests, and $7.7 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses),* as compared to the same period in 2013.

For the year ended December 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $75.7 million as compared to $20.3 million during the same period in 2013, an increase of $55.4 million. Net earnings per share totalled $0.31 for the year ended December 31, 2014, as compared to $0.07 during the same period in 2013.

During the year ended December 31, 2014, cash provided by operating activities totalled $192.7 million or $0.90 per share as compared to cash provided by operating activities of $98.9 million, or $0.48 per share during the same period in 2013. During the year ended December 31, 2014, adjusted funds from operations, a non-GAAP measure, totalled $206.5 million or $0.92 per share as compared to adjusted funds from operations of $154.9 million, or $0.73 per share during the same period in 2013, an increase of $51.6 million.

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

2014 Fourth Quarter Results From Operations

Key Selected Fourth Quarter Financial Information

(all dollar amounts in $ millions except per share information)	Three months ended December 31 2014	2013
Revenue	**$ 259.3**	$ 205.3
Adjusted EBITDA [1]	**84.3**	68.5
Cash provided by operating activities	**96.5**	28.4
Adjusted funds from operations [1]	**65.9**	46.0
Net earnings attributable to Shareholders from continuing operations	**33.1**	19.8
Net earnings attributable to Shareholders	**31.6**	13.2
Adjusted net earnings [1]	**35.2**	18.8
Dividends declared to Common Shareholders	**25.4**	17.6
Weighted Average number of common shares outstanding	**230,664,583**	206,219,121
Per share		
Basic net earnings/(loss) from continuing operations	**$ 0.13**	$ 0.09
Basic net earnings/(loss)	**$ 0.13**	$ 0.06
Adjusted net earnings [1, 2,]	**$ 0.14**	$ 0.08
Diluted net earnings/(loss)	**$ 0.12**	$ 0.06
Cash provided by operating activities [1, 2,]	**$ 0.42**	$ 0.14
Adjusted funds from operations [1, 2]	**$ 0.27**	$ 0.22
Dividends declared to Common Shareholders	**$ 0.10**	$ 0.09

[1] Non-GAAP Financial Measures

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

For the three months ended December 31, 2014, APUC experienced an average U.S. exchange rate of approximately $1.136 as compared to $1.050 in the same period in 2013. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended December 31, 2014, APUC reported total revenue of $259.3 million as compared to $205.3 million during the same period in 2013, an increase of $54.0 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

(all dollar amounts in $ millions)		Quarter ended December 31, 2014
Comparative Prior Period Revenue	$	205.3
Significant Changes:		
Generation Group		
Renewable:		
Effect of hydrology resource compared to comparable period in prior year		1.6
Increased wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities		1.2
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities		1.1
Start of commercial operations of the Cornwall Solar Facility		0.7
Decreased sales due to reduced retail customer load at the Maritime region		(0.9)
Distribution Group		
Increased revenue due to acquisition of the New England Gas System		10.5
Electric Systems - Revenue increase at the electric systems predominantly due to higher customer demand at the Granite State Electric System		4.3
Natural Gas Systems - Revenue increase due to higher customer demand as a result of colder than average weather at the EnergyNorth, Midstates, and Peach State Natural Gas Systems		8.5
Rate Cases – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $1.6 million) and Peach State Gas System (U.S. $2.2 million)		3.8
Water and Waste Systems – Revenue increase due to the increased customer demand		1.1
Increase due to acquisition of New England Gas System's water heater rental service (U.S. $0.8 million) and increased revenues at Peach State Gas System's Fort Benning operation (U.S. $1.0 million)		1.8
Impact of the stronger U.S. dollar		21.2
Other		(0.9)
Current Period Revenue	$	259.3

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

Adjusted EBITDA in the three months ended December 31, 2014 totalled $84.3 million as compared to $68.5 million during the same period in 2013, an increase of $15.8 million or 23.1%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in December 2013, impact of rate case settlements, increased hydrology and wind resources, and increase customer demand at the EnergyNorth and Midstates Gas Systems. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2014, net earnings attributable to Shareholders from continued operations totalled $33.1 million as compared to $19.8 million during the same period in 2013, an increase of $13.3 million. The increase was due to $20.3 million in increased earnings from operating facilities, $1.5 million in decreased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)*, $0.3 million in decreased interest expense, $0.7 million due to a gain on sale of assets, and $4.9 million in increased allocation of earnings to non-controlling interests, as compared to the same period in 2013. These items were partially offset by $2.1 million in increased depreciation and amortization expenses, $5.4 million in increased administration charges, $0.4 million in decreased foreign exchange gains, $0.5 million in decreased interest and dividend income, $1.0 million in increased acquisition costs, $0.3 million in increased write-downs on notes receivable and property, plant, and equipment, and $4.7 million in decreased gains from derivative instruments.

For the three months ended December 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $31.6 million as compared to net earnings attributable to Shareholders of $13.2 million during the same period in 2013, an increase of $18.4 million. Net earnings per share totalled $0.13 for the three months ended December 31, 2014, as compared to net earnings per share of $0.06 during the same period in 2013.

During the three months ended December 31, 2014, cash provided by operating activities totalled $96.5 million or $0.42 per share as compared to cash provided by operating activities of $28.4 million, or $0.14 per share during the same period in 2013. During the three months ended December 31, 2014, adjusted funds from operations totalled $65.9 million or $0.27 per share as compared to adjusted funds from operations of $46.0 million, or $0.22 per share during the same period in 2013. The change in adjusted funds from operations in the three months ended December 31, 2014, is primarily due to increased earnings from operations, as compared to the same period in 2013.

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

GENERATION BUSINESS GROUP

Renewable Energy Division

	Three months ended December 31			Year ended December 31		
	Long Term Average Resource	2014	2013	Long Term Average Resource	2014	2013
Performance (GW-hrs sold)						
Hydro Facilities:						
Maritime Region	45.8	38.0	37.9	177.8	146.2	203.1
Quebec Region[1]	72.8	72.3	68.1	274.9	259.4	277.7
Ontario Region[2]	33.8	38.7	39.3	139.8	144.5	90.4
Western Region	12.6	13.4	12.1	65.0	74.1	66.6
	165.0	162.4	157.4	657.5	624.2	637.8
Wind Facilities:						
St. Damase[3]	6.7	4.7	—	6.7	4.7	—
St. Leon	121.4	119.9	116.5	430.2	441.4	398.0
Red Lily[4]	24.1	23.8	22.8	88.5	87.7	79.0
Sandy Ridge	43.6	46.7	38.7	158.3	149.0	138.7
Minonk	195.8	195.4	182.8	673.3	648.5	621.8
Senate	140.0	139.0	133.8	520.4	537.6	524.5
Shady Oaks	100.4	92.2	88.7	364.0	339.9	317.1
	632.0	621.7	583.3	2,241.4	2,208.8	2,079.1
Solar Facilities:						
Cornwall	2.2	1.8	—	11.8	12.8	—
Total Performance	799.2	785.9	740.7	2,910.7	2,845.8	2,716.9

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

[2] The Generation Group's Long Sault hydro facility was offline during most of the first nine months of 2013. Insurance proceeds were received to compensate for lost revenue.

[3] The St Damase Wind Facility achieved commercial operation on December 2, 2014. Long term average resource and production represent production from December 2 to December 31, 2014.

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

For the twelve months ended December 31, 2014, the Renewable Energy Division generated 2,845.8 GW-hrs of electricity. This level of production represents sufficient energy to supply the equivalent of 210,800 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 2,086,900 tons of CO_2 gas was prevented from entering the atmosphere.

	Three months ended December 31		Year ended December 31	
(all dollar amounts in $ millions)	2014	2013	2014	2013
Revenue[1]				
Hydro Sales	$ 16.8	$ 15.9	$ 65.1	$ 61.9
Wind	26.9	24.5	88.8	83.8
Solar	0.7	—	5.5	—
Total Revenue	**$ 44.4**	$ 40.4	**$ 159.4**	$ 145.7
Less:				
Cost of Sales - Energy[2]	(1.5)	(3.8)	(16.7)	(8.7)
Realized gain/(loss) on hedges[3]	(0.2)	0.3	3.6	0.5
Net Energy Sales	**$ 42.7**	$ 36.9	**$ 146.3**	$ 137.5
Renewable Energy Credits ("REC")[4]	4.0	2.6	11.7	5.9
Other Revenue	0.4	0.2	1.6	1.2
Total Net Revenue	**$ 47.1**	$ 39.7	$ 159.6	$ 144.6
Expenses & Other Income				
Operating expenses	(11.0)	(11.2)	(46.1)	(40.3)
Interest and Other income	0.4	0.5	1.7	1.9
HLBV income/(loss)	8.9	6.8	27.2	20.4
Divisional operating profit	**$ 45.4**	$ 35.8	**$ 142.4**	$ 126.6

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

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

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

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

2014 Fourth Quarter Operating Results

For the three months ended December 31, 2014, the hydro facilities generated 162.4 GW-hrs of electricity, as compared to 157.4 GW-hrs produced in the same period in 2013, an increase of 3.2%. The increased generation is largely attributable to significantly better hydrology in Quebec that more than offset the Donnacona Hydro Facility being offline throughout the quarter. See the "Quebec Dam Safety Act" section for a further discussion on the Donnacona Hydro Facility.

During the three months ended December 31, 2014, the hydro facilities generated electricity equal to 98.4% of long-term projected average resources as compared to 95.2% during the same period in 2013. During the three months ended December 31, 2014, the Ontario and Western Hydro regions achieved production greater than their long-term averages. The Quebec region was below the long term average due to Donnacona being offline. Excluding Donnacona, the Quebec region would have achieved 108% of the LTAR.

For the three months ended December 31, 2014 , revenue from the hydro facilities totalled $16.8 million as compared to $15.9 million during the same period in 2013, an increase of $0.9 million. Revenue from generation at the hydro facilities located in the Quebec region increased by $1.4 million, as compared to the same period in 2013. The increase is attributed to more favorable hydrology in the Quebec region. This was offset by decreased revenues in the Maritime region of $0.7 million, primarily due to decreased customer load served. Revenue in the Maritime region primarily consists of the sale of the off-take from the Tinker Hydro Facility through wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Hydro Facility, and other revenue.

For the three months ended December 31, 2014 , energy purchase costs at the Maritime region totalled $1.5 million, as compared to $3.8 million during the same period in 2013, a decrease of $2.3 million. The decrease in the energy purchase costs for the three months ended December 31, 2014 were primarily due to decreased retail customer load served in the quarter requiring reduced energy purchases from the market as the Maritime region was able to generate sufficient energy to meet its retail demand. During this period, approximately 21.4 GW-hrs of energy was purchased at market and fixed rates averaging U.S. $61 per MW-hr.

During the three months ended December 31, 2014 , the Maritime region generated approximately 69% of the load required to service its customers, as compared to 44% in the same period in 2013. To mitigate the risk of higher average energy prices, certain power hedges are entered into as part of risk mitigation strategies. For the three months ended December 31, 2014 , $0.2 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments in the financial statements.

For the three months ended December 31, 2014 , the wind facilities produced 621.7 GW-hrs of electricity, as compared to 583.3 GW-hrs produced in the same period in 2013, an increase of 6.6%. The higher generation was a result of increased wind resources at all sites and the start of production at the newest facility, the St. Damase Wind Facility, which achieved COD on December 2, 2014. The St. Damase wind facility generated 4.7 GW-hrs.

During the three months ended December 31, 2014 , the wind facilities (excluding the St. Damase Wind Facility) generated electricity equal to 98.4% of long-term projected average resources, as compared to 93.3% during the same period in 2013, due to variability in the wind resource.

For the three months ended December 31, 2014 , revenue from the wind facilities totalled $26.9 million as compared to $24.5 million during the same period in 2013, an increase of $2.4 million. Revenue increases were evident at all wind facilities due mainly to the 38.4 GW/h increase in production due to an increase in wind resources, as compared to the same period last year. As a result, revenues from the Generation Group’s Canadian wind facilities increased $0.8 million, while the U.S. wind facilities increased $1.9 million, as compared to the same period last year. These gains were partly offset by $0.3 million in hedge settlements under the Minonk, Senate and Sandy Ridge Wind Facilities' power hedges.

For the three months ended December 31, 2014 , REC revenue totalled $4.0 million, as compared to $2.6 million in the same period in 2013, an increase of $1.4 million, primarily attributed to increased market pricing in all regions with the PJM region having the largest impact. The increase in market pricing is largely caused by the annually increasing renewable requirement of the RPS (Renewable Portfolio Standard) outpacing the increase in supply of available RECs. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the three months ended December 31, 2014 , REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the three months ended December 31, 2014 , the Generation Group's solar facility located in Ontario had its third full quarter of operations generating 1.8 GW-hrs of electricity, which is equal to 18.2% below long-term average resources. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT PPA with the Ontario Power Authority.

Revenue from generation at the Generation Group’s new solar facility located in Cornwall, Ontario totalled $0.7 million for the period. As commercial operation was achieved late in the first quarter of 2014, there is no comparative data from the previous year.

For the three months ended December 31, 2014 , operating expenses excluding energy purchases totalled $11.0 million, as compared to $11.2 million during the same period in 2013, a decrease of $0.2 million. The decrease was primarily attributable to greater inventorying of REC costs at the Senate Wind facility partly offset by operating costs at the new Cornwall Solar Facility.

The Red Lily I Wind Facility located in Saskatchewan produced 23.8 GW-hrs of electricity for the three months ended December 31, 2014 . The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the three months ended December 31, 2014, the Generation Group earned fees of $0.3 million (which is classified as other revenue) and interest income of $0.4 million from the Red Lily I Wind Facility.

For the three months ended December 31, 2014 , interest and other income totalled $0.4 million, consistent with the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of the Generation Group’s earnings from its investment in the Red Lily I Wind Facility, as discussed above.

For the three months ended December 31, 2014 , the value of net tax attributes generated amounted to an approximate HLBV income of $8.9 million, an increase of $2.1 million compared to the prior year. The increase was attributable to increased production, a stronger U.S. dollar exchange rate, and the reduced economic interest in the projects attributable to tax equity.

For the three months ended December 31, 2014 , the Renewable Energy Division’s operating profit totalled $45.4 million, as compared to $35.8 million during the same period in 2013, an increase of $9.6 million; $2.5 million of the increase is attributable to the stronger U.S. dollar.

2014 Twelve Month Operating Results

For the twelve months ended December 31, 2014 , the hydro facilities generated 624.2 GW-hrs of electricity, as compared to 637.8 GW-hrs produced in the same period in 2013, a decrease of 2.1%. The slight decrease in generation is largely due to a decrease in production in the Maritime region due to lower hydrology in the first 3 quarters of the year, almost completely offset by an increased production in the Ontario region with the Long Sault facility return to service, which was offline for the majority of the first and second quarter of 2013.

During the twelve months ended December 31, 2014 , the hydro facilities generated electricity equal to 94.9% of long-term projected average resources, as compared to 103.4% during the same period in 2013. During the twelve months ended December 31, 2014 , the Ontario and Western Hydro regions achieved production above their long-term averages. The Quebec and Maritime regions were below the long term average production. Had the Quebec region's Donnacona facility been on line, the region would have achieved 102% of the long term average hydrological resource.

For the twelve months ended December 31, 2014 , revenue from the hydro facilities totalled $65.1 million, as compared to $61.9 million during the same period in 2013, an increase of $3.2 million. Revenue from generation in the Ontario region increased by $0.7 million due to the Long Sault Hydro Facility being back on-line for the full year 2014. The Quebec and Western regions experienced a decrease of $0.3 million and $0.7 million, respectively. The decrease in the Quebec region is primarily due to the Donnacona Hydro Facility being offline, while the decrease in the Western region is primarily due to lower market pricing on the unhedged portion of the production. The increase in production at the Western region

caused the market exposed production amount to increase 8% while the weighted average market price fell by more than 50%. Revenue from the Maritime region increased $3.5 million, primarily due to increased retail customer load served.

For the twelve months ended December 31, 2014 , energy purchases totalled $16.7 million, as compared to $8.7 million during the same period in 2013, an increase of $8.0 million. Increased energy purchase costs for the twelve months ended December 31, 2014 were primarily due to lower hydrology in the Maritime region in the first half of the year, which required increased energy purchases from external suppliers at higher average prices. During this period, purchases of approximately 166.0 GW-hrs of energy at market and fixed rates averaging U.S. $91 per MW-hr were made. During the twelve months ended December 31, 2014 , the Maritime region generated approximately 46% of the load required to service its customers, as compared to 67% in the same period in 2013. To mitigate the risk of higher average energy prices, the Maritime region had previously entered into certain power hedges as part of its risk mitigation strategies. For the twelve months ended December

31, 2014, $3.6 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments on the Consolidated Statement of Operations.

For the twelve months ended December 31, 2014, the wind facilities produced 2,208.8 GW-hrs of electricity, as compared to 2,079.1 GW-hrs produced in the same period in 2013, an increase of 6.2%. The increased generation was a result of stronger wind resources at the St. Leon, Minonk, Sandy Ridge, and Senate Wind Facility along with the St. Damase Wind Facility which achieved COD on December 2, 2014.

During the twelve months ended December 31, 2014, the wind facilities generated electricity equal to 98.5% of long-term projected average resources, as compared to 93.1% during the same period in 2013. For the twelve months ended December 31, 2014, revenue from the wind facilities totalled $88.8 million, as compared to $83.8 million during the same period in 2013, an increase of $5.0 million. The increase in revenue was due primarily to a 129.7 GW/h increase in production from stronger wind resources, as compared to the same period last year. As a result, revenues from the Generation Group's Canadian wind facilities increased $3.5 million, while the U.S. wind facilities increased $1.5 million, net of hedge settlements under the Minonk, Senate and Sandy Ridge Wind Facilities' power hedges.

For the twelve months ended December 31, 2014, REC revenue totalled $11.7 million, as compared to $5.9 million in the same period in 2013, an increase of $5.8 million, primarily a result of increased market pricing and a greater number of RECs generated and sold. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the twelve months ended December 31, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the twelve months ended December 31, 2014, the Generation Group's solar facility located in Ontario generated 12.8 GW-hrs of electricity, which is equal to 8.5% above long-term average resources from the commercial operation date. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT PPA with the Ontario Power Authority.

Revenue from generation totalled $5.5 million for the period. The facility achieved commercial operation on March 27, 2014 and therefore there is no comparative data from the previous year.

For the twelve months ended December 31, 2014, operating expenses excluding energy purchases totalled $46.1 million, as compared to $40.3 million during the same period in 2013, an increase of $5.8 million. The increase was due to the appreciation of the U.S. dollar, operating costs for Cornwall's first year of operations, and cost of RECs contracted in the first quarter of 2014 but produced in the fourth quarter of 2013.

For the twelve months ended December 31, 2014, interest and other income totalled $1.7 million, as compared to $1.9 million during the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of the Generation Group's earnings from its investment in Red Lily I Wind Facility, as discussed below.

The Red Lily I Wind Facility located in Saskatchewan produced 87.7 GW-hrs of electricity for the twelve months ended December 31, 2014. The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the twelve months ended December 31, 2014, the Generation Group earned fees of $1.3 million (which is classified as other revenue) and interest income of $1.6 million from the Red Lily I Wind Facility.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes, primarily related to electricity production generated by the Generation Group in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the twelve months ended December 31, 2014 amounted to an approximate HLBV income of $27.2 million, as compared to $20.4 million in the prior year. The increase of $6.8 million was primarily a result of a stronger U.S. dollar exchange rate, increased production at all U.S. sites, and a higher income allocation to the Generation Group due to the reduced economic interest of Tax Equity investors in the projects.

For the twelve months ended December 31, 2014, the Renewable Energy Division's operating profit totalled $142.4 million, as compared to $126.6 million during the same period in 2013, an increase of $15.8 million; $3.5 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

Thermal Energy Division	Three months ended December 31, 2014			Three months ended December 31, 2013		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance (GW-hrs sold)	**26.3**	**35.1**	**61.4**	28.8	35.6	64.4
Performance (steam sales – billion lbs)	**157.3**	**—**	**157.3**	161.3	—	161.3
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	**$ 4.7**	**$ 4.3**	**$ 9.0**	$ 4.6	$ 3.9	$ 8.5
Less:						
Cost of Sales – Fuel	**(3.1)**	**(1.9)**	**(5.0)**	(3.1)	(1.5)	(4.6)
Net Energy/Steam Sales	**$ 1.6**	**$ 2.4**	**$ 4.0**	$ 1.5	$ 2.4	$ 3.9
Other Revenue	**0.1**	**0.6**	**0.7**	0.2	0.6	0.8
Total Net Revenue	**$ 1.7**	**$ 3.0**	**$ 4.7**	$ 1.7	$ 3.0	$ 4.7
Expenses						
Operating Expenses	**$ (0.7)**	**$ (1.3)**	**$ (2.0)**	$ (0.9)	$ (1.2)	$ (2.1)
Facility operating profit	**$ 1.0**	**$ 1.7**	**$ 2.7**	$ 0.8	$ 1.8	$ 2.6
Interest and other income			**(0.3)**			0.1
Divisional operating profit			**$ 2.4**			$ 2.7

2014 Fourth Quarter Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations. See Financial Statement note 17 for details.

For the three months ended December 31, 2014 , the Thermal Energy Division's operating profit was $2.4 million, as compared to $2.7 million in the same period in 2013, a decrease of $0.3 million. Operating profit contributions for the three months ended December 31, 2014 were $1.0 million from the Windsor Locks Thermal Facility and $1.7 million from the Sanger Thermal Facility, as compared to $0.8 million and $1.8 million, respectively, during the same period in 2013. Interest and other income for the three months ended December 31, 2014 was a loss of $0.3 million, as compared to income of $0.1 million in the prior period. As a result of the stronger U.S. dollar, operating profit increased by $0.2 million.

Windsor Locks Thermal Facility

For the three months ended December 31, 2014 , the Windsor Locks Thermal Facility sold 157.3 billion lbs of steam and 26.3 GW-hrs of electricity, as compared to 161.3 billion lbs of steam and 28.8 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $4.7 million (U.S. $4.1 million), as compared to $4.6 million (U.S. $4.4 million) in the same period in 2013. The change in electricity/steam sales is attributed to lower production, but partly offset by a higher average price for gas as a result of the better ISO NE electricity market price. Gas costs for the period were $3.1 million (U.S. $2.7 million), as compared to $3.1 million (U.S. $2.9 million) in the same period in 2013. The change in gas costs is a result of decreased production, partly offset by increases in the average landed cost of natural gas per MMBTU in the quarter, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2014 , net sales at the Windsor Locks Thermal Facility totalled $1.6 million (U.S. $1.4 million) as compared to $1.5 million (U.S. $1.5 million) in the same period in 2013. This variance was driven by a small increase in revenue, which was largely the result of the stronger US dollar, and a small decrease in gas costs.

Operating expenses excluding fuel costs were $0.7 million (U.S. $0.6 million), as compared to $0.9 million (U.S. $0.8 million) in the same period in 2013. The decrease was primarily due to an increase in inventorying of REC costs vs the same period last year. Generated RECs that have not been sold under a customer contract are recorded as an increase to inventory with an offset booked to operating expense. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended December 31, 2014 was $1.0 million (U.S. $0.9 million), as compared to $0.8 million (U.S. $0.9 million) in the same period in 2013; $0.2 million of the increase is attributable to the stronger U.S. dollar.

Sanger Thermal Facility

For the three months ended December 31, 2014 , the Sanger Thermal Facility sold 35.1 GW-hrs of electricity, as compared to 35.6 GW-hrs of electricity in the comparable period of 2013.

For the three months ended December 31, 2014 , the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $4.3 million (U.S. $3.8 million), as compared to $3.9 million (U.S. $3.7 million) in the same period in 2013, an increase of $0.4 million. The increase in energy/steam sales is primarily due to an increase in the contract basis differential and passing on higher gas prices to our customer, as compared to the same period in 2013. Capacity revenues remained unchanged at $1.7 million. Gas costs for the period were $1.9 million (U.S. $1.7 million), as compared to $1.5 million (U.S. $1.5 million) in the same period in 2013. The increase in gas costs is largely due to a an increase in the average cost of natural gas per MMBTU and a stronger U.S. dollar, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2014 , net energy sales at the Sanger Thermal Facility totalled $2.4 million (U.S. $2.1 million), as compared to $2.4 million (U.S. $2.2 million) during the same period in 2013.

Operating expenses excluding natural gas costs were $1.3 million (U.S. $1.2 million), as compared to $1.2 million (U.S. $1.1 million) in the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the three months ended December 31, 2014 was $1.7 million (U.S. $1.5 million), as compared to $1.8 million (U.S. $1.6 million) during the same period in 2013; the net U.S. dollar impact on the change in the Sanger Thermal Facility's net operating income was nil.

	Twelve months ended December 31, 2014			Twelve months ended December 31, 2013		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance(GW-hrs sold)	**112.4**	**134.2**	**246.6**	115.3	137.4	252.7
Performance(steam sales – billion lbs)	**609.1**	**—**	**609.1**	623.0	—	623.0
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	**$ 23.1**	**$ 19.8**	**$ 42.9**	$ 17.6	$ 16.9	$ 34.5
Less:						
Cost of Sales – Fuel	**(15.1)**	**(7.5)**	**$ (22.6)**	(11.2)	(6.0)	(17.2)
Net Energy/Steam Sales	**$ 8.0**	**$ 12.3**	**$ 20.3**	**$ 6.4**	**$ 10.9**	**$ 17.3**
Other revenue	**1.3**	**1.9**	**3.2**	0.5	1.9	2.4
Total net revenue	**$ 9.3**	**$ 14.2**	**$ 23.5**	**$ 6.9**	**$ 12.8**	**$ 19.7**
Expenses						
Operating expenses	**(4.4)**	**(5.0)**	**(9.4)**	(3.7)	(4.8)	(8.5)
Facility operating profit	**$ 4.9**	**$ 9.2**	**$ 14.1**	**$ 3.2**	**$ 8.0**	**$ 11.2**
Interest and other income (loss)			**$ (0.5)**			$ 0.2
Divisional operating profit			**13.6**			11.4

2014 Twelve Month Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations. See Financial Statement note 17 for details.

For the twelve months ended December 31, 2014 , the Thermal Energy Division's operating profit was $13.6 million, as compared to $11.4 million in the same period in 2013, an increase of $2.2 million. The Windsor Locks Thermal Facility contributed $4.9 million, while the Sanger Thermal Facility contributed $9.2 million of operating profit during the twelve months ended December 31, 2014 , as compared to $3.2 million and $8.0 million, respectively, during the same period in the prior year. Interest and other income for the twelve months ended December 31, 2014 was a loss of $0.5 million, as compared to income of $0.2 million during the same period in the prior year. As a result of the stronger U.S. dollar, operating profit was positively impacted by $1.1 million.

Windsor Locks Thermal Facility

For the twelve months ended December 31, 2014 , the Windsor Locks Thermal Facility sold 609.1 billion lbs of steam and 112.4 GW-hrs of electricity, as compared to 623.0 billion lbs of steam and 115.3 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $23.1 million (U.S. $20.9 million), as compared to $17.6 million (U.S. $17.1 million) in the same period in 2013. The increase in electricity/steam sales is attributed to a higher average price for gas as a result of the better ISO NE electricity market price driven by seasonally low temperatures in the first half of 2014. Gas costs for the period were $15.1 million (U.S. $13.7 million), as compared to

$11.2 million (U.S. $10.9 million) in the same period in 2013. The increase in gas costs is a result of increases in the average landed cost of natural gas per MMBTU in the first three quarters of the year, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2014, net energy/steam sales at the Windsor Locks Thermal Facility totalled $8.0 million (U.S. $7.2 million), as compared to $6.4 million (U.S. $6.2 million) during the same period in 2013, an increase of $1.6 million (U.S. $1.0 million).

Operating expenses excluding natural gas costs were $4.4 million (U.S. $4.0 million), as compared to $3.7 million (U.S. $3.6 million) during the same period in 2013. The increase is primarily attributable to a stronger U.S. dollar and the cost of RECs sold in the first nine months of 2014 but generated in 2013 (an offset to operating expense is booked when a REC is generated and is recorded as inventory). The Windsor Locks Thermal Facility's resulting net operating income for the twelve months ended December 31, 2014 was $4.9 million (U.S. $4.4 million), as compared to $3.2 million (U.S. $3.1 million) in the same period in 2013, an increase of $1.7 million; $0.4 million of the increase is attributable to the stronger U.S. dollar.

Sanger Thermal Facility

For the twelve months ended December 31, 2014, the Sanger Thermal Facility sold 134.2 GW-hrs of electricity, as compared to 137.4 GW-hrs of electricity in the comparable period of 2013. The decrease in production is due to the Sanger Thermal Facility's planned outage and limitation of run hours in the first quarter of 2014.

For the twelve months ended December 31, 2014, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $19.8 million (U.S. $17.9 million), as compared to $16.9 million (U.S. $16.4 million) in the same period in 2013, an increase of $2.9 million. The increase in energy/steam sales is attributed primarily to increased gas prices, as compared to 2013, which is a pass through to customers. Capacity revenues remained unchanged at $8.4 million. Gas costs for the period were $7.5 million (U.S. $6.8 million), as compared to $6.0 million (U.S. $5.8 million) in the same period in 2013. The increase in gas costs is largely due to a 19% increase in the average cost of natural gas per MMBTU and a stronger U.S. dollar, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2014, net energy sales at the Sanger Thermal Facility totalled $12.3 million (U.S. $11.1 million), as compared to $10.9 million (U.S. $10.6 million) during the same period in 2013, an increase of $1.4 million primarily due to more favorable pricing on the variable portion of the supply contract and an increase in the U.S. dollar exchange rate.

Operating expenses excluding natural gas costs were $5.0 million (U.S. $4.5 million), as compared to $4.8 million (U.S. $4.7 million) during the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the twelve months ended December 31, 2014 was $9.2 million (U.S. $8.3 million), as compared to $8.0 million (U.S. $7.8 million) in the same period in 2013, an increase of $1.2 million; $0.7 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

Development Division

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

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

Project Name	Location	Size (MW)	Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Projects Completed						
Cornwall Solar Facility[1]	Ontario	10	$ 47.6	2014	20	14.4
St. Damase Wind Facility[1]	Quebec	24	$ 69.7	2014	20	76.9
Total Completed		**34**	**$ 117.3**			**91.3**
Projects in Construction						
Morse Wind Project[1]	Saskatchewan	23	$ 81.3	2015	20	104.0
Bakersfield I Solar Project[1,2]	California	20	$ 67.9	2015	20	53.3
Total Project in Construction		**43**	**$ 149.2**			**157.3**
Projects in Development						
Odell Wind Project[1,3]	Minnesota	200	$ 374.5	2015/16	20	814.7
Val Eo Wind Project[1,4,5]	Quebec	24	$ 70.0	2016/17	20	66.0
Bakersfield II Solar Project[1,6]	California	10	$ 31.3	2016	20	26.5
Amherst Island Wind Project[1]	Ontario	75	$ 260.0	2016/17	20	235.0
Chaplin Wind Project[1,7]	Saskatchewan	177	$ 340.0	2017/18	25	720.0
Total Projects in Development		**486**	**$ 1,075.8**			**1,862.2**
Total in Construction and Development		**529**	**$ 1,225.0**			**2,019.5**

1 PPA Signed.

2 Total cost of the project is expected to be approximately $58.5 million in U.S. dollars.

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

4 The Val Eo Wind Project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2015 and the101 MW 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.

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

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

7 The Chaplin project is being developed in two phases: Phase I of the project , which comprises approximately 35 MW of the total project, will be erected in 2017 and Phase II of the project, which comprises the remaining approximately 142 MW, will be constructed following evaluation of the wind resource at the site, and completion of satisfactory permitting.

Projects Completed

Cornwall Solar Facility

Construction of the project is now complete and commercial operation was achieved on March 27, 2014. The Cornwall Solar Facility is anticipated to have energy production of 14.4 GW-hrs/year. The Cornwall Solar Facility has been granted a 10 MW Feed In Tariff ("FIT") contract by the OPA, with a 20 year term and a rate of $443/MW-hr, resulting in expected initial annual revenues of approximately $6.2 million. Operating results from this project are now being reported in the Generation Group's renewable energy results.

St. Damase Wind Facility

Construction of the St. Damase Wind Facility is now complete and commercial operation was achieved on December 2, 2014. The facility has a 20 year PPA with Hydro Quebec. It is a 24 MW facility and is expected to generate $7.4 million in revenue in its first full year of operations.

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Facility will qualify as CRCE, and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec CRCE Tax Credit. In June 2014, the government of Quebec released the 2014-2015 budget, which included a 20% reduction in value for a wide range of tax credits, including the Quebec CRCE Tax Credit. The estimated value of the Quebec CRCE tax credit for the St. Damase project is expected to be approximately $16.6 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. Operating results from this project are now being reported in the Generation Group's renewable energy results.

Projects in Construction

Morse Wind Project

The Morse Wind Project is comprised of three contiguous projects with 25 MW of aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

Based on the award of 25 MW under Saskatchewan's Green Options Partner Program, SaskPower has offered the Generation Group a 20 year contract for the procurement of 23 MW of wind generation to match the nameplate capacity of the proposed turbines.

The Generation Group executed an asset purchase agreement with a local developer, Kineticor, to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by the Generation Group independently. All of the individual projects comprising the Morse wind project were selected by SaskPower in accordance with the SaskPower Green Options Partners Program.

The turbine supply agreements have been executed with Siemens and the Balance of Plant Engineering, Procurement and Construction agreement has been signed. The turbine placement has been finalized and registered land leases have been executed with the landowners. Installation of access roads and foundations are completed, and turbine delivery commenced in January 2015. Seven of ten turbine have been erected, and the project is expected to be operational by March 31, 2015.

Bakersfield I Solar Project

The Generation Group has entered into an agreement for the continuing development of a 20 MWac solar powered generating station located in Kern County, California. Following commissioning, the Bakersfield Solar Project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement with expected first full year revenues of U.S. $4.7 million. The Generation Group has entered into a partnership agreement with a third party (the "Tax Partner") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. The Tax Partner will contribute U.S. $22.0 million to the project with the remaining of the total estimated cost of U.S. $58.5 million to be funded by the Generation Group.

Construction of the project commenced in the second quarter of 2014 and was placed in service on December 30, 2014. Testing to ensure the plant will be ready and available for commercial operations was conducted and confirmed by the Generation Group and independent engineers. Final construction efforts continue, with the project expected to reach full commercial operation in the first quarter of 2015.

Projects in Development

Odell Wind Project

The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and renewable energy credits 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 is expected to begin in the second quarter of 2015, with total costs estimated at U.S. $322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in late 2015 or early 2016.

Val-Éo Wind Project

Phase one of the Val-Éo Wind Project is located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo Wind cooperative formed by community

based landowners and the Generation Group. The first 24 MW phase of the project is expected to be comprised of eight wind turbines, producing approximately 66.0GW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in 2015 with commercial operations commencing in 2016. The second phase of the project would entail the development of an additional 101 MW. The permitting and the Environmental Impact Assessment are ongoing with a projected provincial minister's decree in early 2015.

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

Commission de Protection du Territoire Agricole Quebec ("CPTAQ") approval has been received for 8 turbine locations, roads, and the collection system. Land option agreements have all been secured, and the process of converting these options is currently underway. Proposals for the procurement of the substation and balance of plant have been received and evaluated. The final construction schedule is pending the signing of the turbine supply agreement.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MW project adjacent to the Generation Group's 20 MW Bakersfield I Solar Project in Kern County, California, which is currently under construction.

The 10 MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20 MW Bakersfield I Solar Project. Construction of Bakersfield I Solar is nearing completion, with commercial operations expected to occur in the first quarter of 2015.

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

Construction of Bakersfield II Solar is anticipated to commence in mid-2015 following receipt of local permits and finalization of necessary construction contracts, subject to approval by the APUC board of directors. Commercial operation is targeted to occur in the first half of 2016.

Amherst Island Wind Project

The Amherst Island Wind Project is located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

The Amherst Island Wind Project is currently contemplated to use Class III wind turbine generator technology. The available wind resource is forecast to produce approximately 235 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Final negotiations on the turbine supply agreement is ongoing. Total capital costs for the facility are currently estimated to be $260 million, and engineering, procurement and construction contractor selection is underway. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and posted to the environmental registry in early January 2014 and has been undergoing technical review. Changes to the project design have been initiated to optimize construction and project performance, which will require a modification of the application documents. Once the REA is issued in final form, it may be appealed by interested parties within 15 days of its release. If the REA is appealed, the appeal process is expected to take up to 6 months. Other permitting processes are progressing according to schedule. The project has a planned construction time frame of 12 to 18 months with most of the construction expected to occur in 2016.

Chaplin Wind Project

In the first quarter of 2012, the Generation Group entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

The project will be split into two phases where Phase I will approximate 35 MW of the total project and is currently planned to be operational in 2017. The first phase will involve installing test turbines to prove the project viability. The second phase, the infill construction phase, will only commence provided the results of the first phase are successful.

The total facility will be constructed at an estimated capital cost of $340.0 million and consist of approximately 77 multi-megawatt wind turbines. In the total project's first full year of operation, the Generation Group expects to achieve EBITDA of $36.5 million. The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of its favorable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

In March 2014, after review of the Project Proposal Environmental Assessment and Supplemental documentation (including the preliminary proposed layout), the project was deemed a development by the Environmental Assessment Branch. An additional detailed environmental review is currently being completed. It is anticipated that the Environmental Assessment documentation will be submitted to the government in the first quarter of 2015. The expected capital costs of the project are approximately $340 million. The Generation Group anticipates entering into a partnership and development agreement using a similar structure to what was utilized in the development of the Red Lily I Facility, in order to facilitate the development of the project and to optimize returns.

Ontario RFP Qualification

The Generation Group has qualified for participation in the anticipated 2015 Large Renewable Procurement I process with the IESO. The Generation Group may submit offers into the expected RFP for up to 100 MW of solar power and up to 100 MW of wind power. The IESO is expected to award up to 140 MW of solar projects and 300 MW of wind projects. RFP bids are due on September 1, 2015, with successful bidders being announced in December 2015.

DISTRIBUTION BUSINESS GROUP

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 488,000 connections in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	December 31, 2014		December 31, 2013	
(all dollar amounts in U.S. $ millions)	Assets	Connections	Assets	Connections
Electricity	**$ 325.0**	**93,000**	$ 276.6	92,000
Natural Gas	**726.0**	**292,000**	661.5	292,000
Water and Wastewater	**261.2**	**103,000**	233.0	97,400
Total	**$ 1,312.2**	**488,000**	$ 1,171.1	481,400
Accumulated Deferred Income Taxes	**$ 79.6**		$ 66.5	

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

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

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 292,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 103,000 connections located in the states of Arkansas, Arizona, Texas, Illinois, and Missouri.

	Three months ended December 31,		Three months ended December 31,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**47.8**	41.9	**54.4**	46.4
Less: Cost of Sales – Electricity	**(29.9)**	(25.2)	**(34.2)**	(26.5)
Net Utility Sales - Electricity	**$ 17.9**	$ 16.7	**$ 20.2**	$ 19.9
Utility natural gas sales and distribution	**102.5**	83.5	**116.8**	88.0
Less: Cost of Sales – Natural Gas	**(65.6)**	(54.1)	**(74.9)**	(57.1)
Net Utility Sales - Natural Gas	**$ 36.9**	$ 29.4	**$ 41.9**	$ 30.9
Net Utility Sales - Water Distribution & Wastewater Treatment	**15.0**	14.0	**18.6**	14.6
Gas Transportation	**6.8**	4.5	**7.7**	4.7
Other Revenue	**3.0**	1.2	**3.5**	1.3
Net Utility Sales	**$ 79.6**	$ 65.8	**$ 91.9**	$ 71.4
Operating expenses	**(39.7)**	(34.0)	**(46.2)**	(35.6)
Other income	**0.8**	0.7	**0.9**	0.6
Distribution Group operating profit	**$ 40.7**	$ 32.5	**$ 46.6**	$ 36.4

2014 Fourth Quarter Operating Results

For the three months ended December 31, 2014, the Distribution Group reported an operating profit of U.S. $40.7 million, as compared to U.S. $32.5 million for the comparable period in the prior year. The increase is primarily due to implementation of higher rates at the Granite State Electric and Peach State Gas Systems and the acquisition of the New England Gas System on December 20, 2013. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $46.6 million, as compared to $36.4 million for the comparable period in the prior year. In addition to the factors described below, operating profit measured in Canadian dollars increased by $5.9 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Three months ended December 31	
	2014	2013
Average Active Electric Connections For The Period		
Residential	**80,000**	78,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**92,000**	90,000
Customer Usage (GW-hrs)		
Residential	**134.9**	146.4
Commercial and Industrial	**230.5**	222.5
Total Customer Usage (GW-hrs)	**365.4**	368.9

For the three months ended December 31, 2014 the electric distribution systems' usage totalled 365.4 GW-hrs, as compared to 368.9 GW-hrs for the same period in 2013, a decrease of 3.5 GW-hrs. The decrease in residential usage can be primarily attributed to a lower number of heating degree days experienced at the CalPeco Electric System's service territory. A heating degree day is generally defined as the number of degrees that a day's average temperature is below 65 degrees Fahrenheit (18 degrees Celsius).

For the three months ended December 31, 2014, the electric distribution systems' revenue from utility electricity sales totalled U.S. $47.8 million, as compared to U.S. $41.9 million during the same period in 2013, an increase of U.S.$5.9 million, or 14.1%. For the three months ended December 31, 2014, fuel and purchased power costs for the electric distribution systems totalled U.S. $29.9 million, as compared to U.S. $25.2 million during the same period in 2013, an increase of U.S. 4.7 million, or 18.7%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, however these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended December 31, 2014 , net utility sales for the electric distribution systems were U.S. $17.9 million, as compared to U.S. $16.7 million during the same period in 2013, an increase of U.S. $1.2 million, or 7%. The increase in net utility sales is primarily attributed to increased rates at the Granite State Electric System as a result of finalization of the general rate case in March 2014. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

Natural Gas Distribution Systems

	Three months ended December 31,	
	2014	2013
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	217,000
Commercial and Industrial	**27,000**	24,000
Total Average Active Natural Gas Connections For The Period	**275,000**	241,000
Customer Usage (MMBTU)		
Residential	**3,918,000**	3,376,000
Commercial and Industrial	**2,885,000**	2,779,000
Total Customer Usage (MMBTU)	**6,803,000**	6,155,000

For the three months ended December 31, 2014 , usage at the natural gas distribution systems totalled 6,803,000 MMBTU, as compared to 6,155,000 MMBTU during the same period in 2013, an increase of 648,000 MMBTU, or 10.5%. The increase in natural gas usage, as compared to the same period in 2013, can primarily be attributed to the acquisition of the

New England Gas System on December 20, 2013, at which usage totalled 1,053,000 MMBTU, and a higher number of heating degree days experienced in the Peach State Gas System's service territory. The increase was partially offset by a lower number of heating degree days experienced in the EnergyNorth Gas System and the Midstates Gas Systems service territories, as compared to the same period in 2013.

For the three months ended December 31, 2014 , revenue excluding transportation revenue from natural gas sales and distribution totalled U.S. $102.5 million, as compared to U.S. $83.5 million during the same period in 2013, an increase of U.S. $19.0 million or 22.8%. For the three months ended December 31, 2014, natural gas purchases totalled U.S. $65.6 million, as compared with U.S. $54.1 million for the same period in 2013, an increase of U.S. $11.5 million or 21.3%. The cost of natural gas is passed through to the natural gas systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended December 31, 2014, net utility sales for the natural gas distribution systems , excluding transportation, totalled U.S. $36.9 million, as compared to U.S. $29.4 million during the same period in 2013, an increase of U.S. $7.5 million, or 25.5%. The increase in net utility sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $4.3 million of the total increase, and a U.S. $3.1 million increase at the Peach State Gas System primarily due to increased rates as a result of the GRAM filing.

For the three months ended December 31, 2014, revenue from gas transportation sales totalled U.S. $6.8 million, as compared to U.S. $4.5 million during the same period in 2013, an increase of U.S. $2.3 million. The increase in gas transportation sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $1.2 million of the total increase, and a U.S. $1.0 million increase at the EnergyNorth Gas System, primarily due to increased customer demand.

Water and Wastewater Distribution Systems

	Three months ended December 31,	
	2014	**2013**
Average Active Connections For The Period		
Wastewater connections	**40,000**	36,900
Water distribution connections	**58,000**	55,900
Total Average Active Connections For The Period	**98,000**	92,800
Gallons Provided		
Wastewater treated (millions of gallons)	**535**	507
Water sold (millions of gallons)	**1,940**	2,080
Total Gallons Provided	**2,475**	2,587

During the three months ended December 31, 2014, the water and wastewater distribution systems provided approximately 1,940 million gallons of water to its customers and treated approximately 535 million gallons of wastewater, as compared to 2,080 million gallons of water and 507 million gallons of wastewater during the same period in 2013. The decrease in the gallons of water provided to customers can be attributed to increased precipitation, primarily in the state of Arizona during the three months ended December 31, 2014, as compared to the comparable period in the prior year.

The increase in average active wastewater and water distribution connections can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014.

For the three months ended December 31, 2014 , revenue from wastewater treatment and water distribution totalled U.S. $6.9 million and U.S. $8.1 million, respectively, as compared to U.S. $6.1 million and U.S. $7.9 million, respectively, during the same period in 2013. The increase in wastewater treatment and water distribution revenue was primarily due to an increase in rates at the LPSCo Water and Sewer System, effective May 1, 2014, and the acquisition of the White Hall Water System on May 30, 2014.

Other Revenue

For the three months ended December 31, 2014 , other revenue totalled U.S. $3.0 million, as compared to $1.2 million during the same period in 2014. The other revenue consists of water heater rental service and a contract to supply gas to Fort Benning.

Operating Expenses

For the three months ended December 31, 2014 , operating expenses, excluding electricity purchases, totalled U.S. $39.7 million, as compared to U.S. $34.0 million during the same period in 2013, an increase of U.S. $5.7 million, or 17%. The major factors resulting in the increase in the Distribution Group's operating expenses in the three months ended December 31, 2014, as compared to the corresponding period in 2013, are set out as follows:

(all dollar amounts in U.S. $ millions)	Quarter ended December 31, 2014
Comparative Prior Period Operating Expenses	$ 34.0
Significant Changes:	
Acquisition of New England Gas System	6.3
Decrease in operating expenses at Granite State Electric Utility and EnergyNorth Gas Utility	(1.4)
Acquisition of White Hall Water System	0.2
Increase in operating expenses at CalPeco Electric System	0.2
Other	0.4
Current Period Operating Expenses	$ 39.7

	Twelve months ended December 31,		Twelve months ended December 31,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**186.8**	161.3	**206.7**	166.2
Less: Cost of Sales – Electricity	**(108.8)**	(94.5)	**(120.5)**	(97.4)
Net Utility Sales - Electricity	**$ 78.0**	$ 66.8	**$ 86.2**	$ 68.8
Utility natural gas sales and distribution	**378.2**	236.0	**419.9**	243.1
Less: Cost of Sales – Natural Gas	**(234.8)**	(144.5)	**(261.1)**	(148.8)
Net Utility Sales - Natural Gas	**$ 143.4**	$ 91.5	**$ 158.8**	$ 94.3
Net Utility Sales - Water Distribution & Wastewater Treatment	**58.7**	55.6	**66.4**	57.4
Gas Transportation	**23.5**	16.8	**26.1**	17.3
Other Revenue	**5.1**	1.2	**5.7**	1.3
Net Utility Sales	**$ 308.7**	$ 231.9	**$ 343.2**	$ 239.1
Operating expenses	**(162.7)**	(127.5)	**(180.4)**	(131.6)
Other income	**3.0**	3.1	**3.4**	3.2
Distribution Group operating profit	**$ 149.0**	**$ 107.5**	**$ 166.2**	$ 110.7

2014 Twelve Month Operating Results

For the twelve months ended December 31, 2014, the Distribution Group reported an operating profit of U.S. $149.0 million, as compared to U.S. $107.5 million for the comparable period in the prior year. The increase is primarily due to the acquisition of the New England Gas System on December 20, 2013, the acquisition of the Peach State Gas System on April 1, 2013, and higher rates at the Granite State Electric System. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $166.2 million, as compared to $110.7 million for the comparable period in the prior year. In addition to the factors discussed below, operating profit measured in Canadian dollars increased by $17.2 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Twelve months ended December 31,	
	2014	**2013**
Average Active Electric Connections For The Period		
Residential	**79,000**	78,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**91,000**	90,000
Customer Usage (GW-hrs)		
Residential	**557.4**	585.9
Commercial and Industrial	**933.4**	905.5
Total Customer Usage (GW-hrs)	**1,490.8**	1,491.4

For the twelve months ended December 31, 2014 , the electric distribution systems' usage totalled 1,490.8 GW-hrs, as compared to 1,491.4 GW-hrs for the same period in 2013. The decrease in residential usage can be primarily attributed to a lower number of heating degree days experienced at the CalPeco Electric System's service territory.

For the twelve months ended December 31, 2014, the electric distribution systems revenue from utility electricity sales totalled U.S. $186.8 million, as compared to U.S. $161.3 million during the same period in 2013, an increase of U.S. $25.5 million, or 15.8%. For the twelve months ended December 31, 2014, fuel and purchased power costs for the electric distribution systems totalled U.S $108.8 million, as compared to U.S. $94.5 million for the same period in 2013, an increase of U.S. $14.3 million, or 15.1%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the twelve months ended December 31, 2014 , net utility sales for the electric distribution systems were U.S. $78.0 million, as compared to U.S. $66.8 million for the same period in 2013, an increase of U.S. $11.2 million, or 16.8%. The increase in net utility sales can be primarily attributed to an increase in distribution rates to customers from finalization of the Granite State Electric System's general rate case, as well as U.S. $2.5 million in additional revenue recognized in the first quarter of 2014, which represented the difference from the interim rates previously granted to the Granite State Electric System and the final rates retroactive to July 1, 2013. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

Natural Gas Distribution Systems

	Twelve months ended December 31,	
	2014	2013
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	204,000
Commercial and Industrial	**26,000**	23,000
Total Average Active Natural Gas Connections For The Period	**274,000**	227,000
Customer Usage (MMBTU)		
Residential	**18,915,000**	12,401,000
Commercial and Industrial	**12,673,000**	8,706,000
Total Customer Usage (MMBTU)	**31,588,000**	21,107,000

For the twelve months ended December 31, 2014, customer usage at the natural gas distribution systems totalled 31,588,000 MMBTU, as compared to 21,107,000 MMBTU during the same period in 2013, an increase of 10,481,000 MMBTU, or 49.7%. The increase in natural gas usage, as compared to the same period in 2013, can be primarily attributed to the acquisitions of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013; the New England Gas System usage totalled 5,273,000 MMBTU.

For the twelve months ended December 31, 2014, revenue from natural gas sales and distribution totalled U.S. $378.2 million, as compared to U.S. $236.0 million during the same period in 2013, an increase of U.S. $142.2 million. For the twelve months ended December 31, 2014, natural gas purchases totalled U.S. $234.8 million, as compared to U.S. $144.5 million for the same period in 2013, an increase of U.S. $90.3 million. The cost of natural gas is passed through to the natural gas distribution systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of results. For the twelve months ended December 31, 2014, net utility sales, excluding transportation, for the natural gas distribution systems totalled U.S. $143.4 million, as compared to U.S. $91.5 million during the same period in 2013, an increase of U.S. $51.9 million, or 57%. The increase is attributed as follows: U.S. $30.5 million increase from the New England Gas System, which was acquired on December 20, 2013; U.S. $4.5 million increase from the EnergyNorth Gas System, primarily due to the colder winter weather experienced during the first quarter of 2014, as compared to the first quarter of 2013; U.S. $15.1 million increase from the Peach State Gas System; primarily attributed to the inclusion of twelve months of operating results in 2014, as compared to nine months in 2013; increased rates as a result of the GRAM filing at the Peach State Gas System; and a U.S. $1.8 million increase from the Midstates Gas Systems due to the colder winter weather experienced during the first quarter of 2014, as compared to the first quarter of 2013.

For the twelve months ended December 31, 2014, revenue from gas transportation sales totalled U.S. $23.5 million, as compared to U.S. $16.8 million during the same period in 2013, an increase of U.S. $6.7 million. The increase in gas transportation sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $6.1 million of the total increase.

Water and Wastewater Distribution Systems

	Twelve months ended December 31,	
	2014	2013
Average Active Connections For The Period		
Wastewater connections	**39,000**	36,600
Water distribution connections	**58,000**	55,800
Total Average Active Connections For The Period	**97,000**	92,400
Gallons Provided		
Wastewater treated (millions of gallons)	**2,127**	2,034
Water sold (millions of gallons)	**8,310**	8,162
Total Gallons Provided	**10,437**	10,196

Average active wastewater and water distribution connections increased primarily due to the acquisition of the White Hall Water and Sewer System on May 30, 2014.

During the twelve months ended December 31, 2014, the water and wastewater distribution systems provided approximately 8,310 million gallons of water to its customers and treated approximately 2,127 million gallons of wastewater, as compared to 8,162 million gallons of water and 2,034 million gallons of wastewater during the same period in 2013. The increase in water sold can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014, and an additional month of operations from the Pine Bluff Water System in the first twelve months of 2014, as compared to the first twelve months of 2013. The increase in wastewater treated is primarily attributed to an increase in wastewater treated at our sewer utilities located in the state of Arizona.

For the twelve months ended December 31, 2014 , revenue from wastewater treatment and water distribution totalled U.S. $26.1 million and U.S. $32.6 million, respectively, as compared to U.S. $24.3 million and U.S. $31.3 million, respectively, during the same period in 2013. Increased rates at the LPSCo Water and Sewer System, effective May 1, 2013, Rio Rico Water System, effective August 1, 2013, and Woodmark Waste System, effective October 1, 2013, are the primary drivers of the increase along with the acquisition of the White Hall Water System on May 30, 2014.

Other Revenue

For the twelve months ended December 31, 2014 , other revenue totalled U.S. $5.1 million, as compared to U.S. $1.2 million during the same period in 2014. The other revenue consists of water heater rental service and a contract to supply gas to Fort Benning.

Operating Expenses

For the twelve months ended December 31, 2014 , operating expenses, excluding electricity purchases, totalled U.S. $162.7 million, as compared to U.S. $127.5 million during the same period in 2013, an increase of U.S. $35.2 million, or 28%. The major factors resulting in the increase in DBG operating expenses in the twelve months ended December 31, 2014, as compared to the corresponding period in 2013, are set out as follows:

(all dollar amounts in U.S. $ millions)		Year to date December 31, 2014
Comparative Prior Period Operating Expenses	$	127.5
Significant Changes:		
Acquisition of New England Gas System		26.3
Increase in operating expenses at the Granite State Electric System and EnergyNorth Gas System		4.6
Increase in operating expenses at the Peach State Gas System		2.2
Increase in operating expenses at the Midstates Gas Systems		0.8
Acquisition of White Hall Water System		0.5
Other		0.8
Current Period Operating Expenses	$	162.7

The primary reason for the increase in operating expenses for the twelve months ended December 31, 2014 , as compared to the corresponding period in 2013, was the acquisition of the New England Gas System on December 20, 2013. The full year of operating expenses, as compared to eleven days of operating expenses in 2013, contributed an additional U.S. $26.3 million.

Operating expenses at the Granite State Electric and EnergyNorth Gas Systems were U.S. $4.6 million higher than the prior fiscal year, primarily due to increased bad debt expense in the first nine months of the year, a property tax assessment related to a prior assessment year, and additional work for leak repairs.

The increase in operating expenses at the Peach State Gas System of U.S. $2.2 million was primarily due to twelve months of operation during the twelve months ended December 31, 2014, as compared to nine months of operation during the nine months ended December 31, 2013. The Peach State Gas System was acquired on April 1, 2013.

The increase in operating expenses at the Midstates Gas Systems of U.S. $0.8 million can be primarily attributed due to increased costs for billings services and communication expenses.

The acquisition of the White Hall Water System on May 30, 2014 resulted in an increase in operating expenses of U.S. $0.5 million during the twelve months ended December 31, 2014.

Regulatory Proceedings

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

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case	$13,000	Final Order issued on March 2014 approving a $9.8 million rate increase effective April 1, 2014.
Granite State Electric System	New Hampshire	General Rate Case - Step Adjustment	$1,200	Final Order issued on March 2014 approving a $1.1 million in step increase for 2014 effective April 1, 2014
Peach State Gas System	Georgia	GRAM	$4,900	Final Order issued on May 2014 approving a $3.2 million rate increase retroactive to February 1, 2014, and the recovery of $1.7 million of carrying charges on deferred rate base in a future GRAM filing.
Peach State Gas System	Georgia	GRAM	$3,900	Final Order issued on December 2014 approving a $3.7 million rate increase effective February 1, 2015.
LPSCo Water System	Arizona	General Rate Case	$3,000	Final Order issued on April 2014 approving a $1.8 million rate increase effective May 1, 2014.
Missouri Gas System	Missouri	General Rate Case	$7,600	Final Order issued on December 2014 approving a $4.9 million rate increase effective January 2, 2015.
Illinois Gas System	Illinois	General Rate Case	$5,700	Final Order issued on February 11, 2015 approving a $4.6 million revenue increase effective February 20, 2015.
Pending Rate Cases				
Pine Bluff Water System	Arkansas	General Rate Case	$2,500	Application was filed on July 2, 2014; Order expected in Q2 2015
EnergyNorth System	New Hampshire	General Rate Case	$16,100	Application filed on August 1, 2014; a temporary rate increase was approved on November 21, 2014 allowing a $7.4M interim increase effective December 1, 2014, retroactive to November 1, 2014 upon approval of permanent rates. A final permanent rates decision is expected in Q3 2015.

Completed Rate Cases

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 commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014.

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 GRAM filing with the GPSC. In January 2014, the Distribution 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. $3.9 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). Commission approval was received on December 2, 2014.

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water 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 addition to a revenue increase, the application sought 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 commission approved a $1.8 million increase in rates effective on May 1, 2014.

On February 6, 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") 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 ISRS surcharge (infrastructure system replacement surcharge). 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 on December 3, 2014, approving a U.S. $4.9 million revenue increase effective January 2, 2015.

On March 31, 2014, the Midstates Gas System filed a rate case with the Illinois Commerce Commission ("ICC") seeking an increase in EBITDA of U.S. $5.7 million. The filing is 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.

Pending Rate Cases

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

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Distribution Group ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. 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.

Acquisition Approval Applications

On September 19, 2014, the Distribution 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 (“Park Water System”). 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.

The acquisition requires the approval of both the California Public Utilities Commission ("CPUC") and the Montana Public Service Commission ("MPSC"). An approval application was filed on November 24, 2014 with the CPUC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to acquire the two water utilities located in California owned by the Park Water Company, Park Central Basin and Apple Valley Ranchos Water. A decision on the California application is expected in the third quarter of 2015. An approval application was also filed on December 15, 2014 with the MPSC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to effectively acquire Mountain Water Company. A decision on the application is expected in the fourth quarter of 2015.

Mountain Water Company is the water utility in Western Montana owned by Park Water Company which serves the municipality of Missoula. Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula (See “Regulatory Risk”).

TRANSMISSION BUSINESS GROUP

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

For its first major project on November 24, 2014, the Transmission Group announced an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, NY and Dracut, MA (the "Project"), which will be operated by Tennessee Gas Pipeline Company, L.L.C. ("Tennessee"). The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with construction anticipated to begin in January 2017 and commercial operations expected by Nov. 1, 2018.

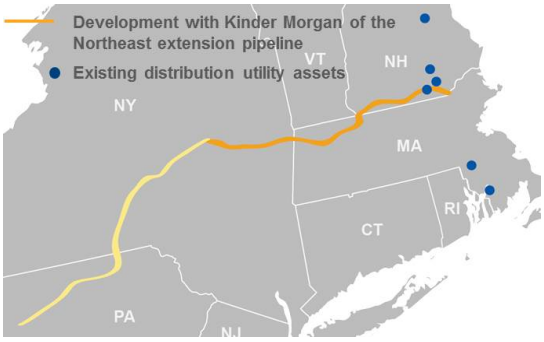
Under the agreement, APUC will initially subscribe for a 2.5% interest in Northeast Expansion LLC. APUC also has an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. $400 million, depending on the final pipeline configuration and design capacity.

The U.S. $3-$4 billion infrastructure project consists of 188 miles of pipeline and six new compressor stations to be constructed through the states of New York, Massachusetts and New Hampshire. The pipeline is designed to provide up to 2.2 Bcf/day of firm gas deliveries to gas distribution utilities, gas fired generation, industrial customers and other New England consumers. Given the proposed route of the project, the Distribution Group will also look to economically expand its gas distribution utility footprint in New Hampshire as well to serve over twenty new communities with natural gas service.

Under the current September 15, 2014 application before the FERC under Docket No. PF 14 - 22, the project sponsor has proposed the following development calendar of events for proceeding with the project:

1st Draft of the Environmental Review	March 6, 2015
2nd Draft of the Environmental Review	June 5, 2015
FERC Section 7 Certificate Application Filed	September, 2015
FERC Section 7 Certificate Approval Received	October 31, 2016
Targeted In- Service of Core NED Project	November 1, 2018

The project route has recently been modified to address a number of comments raised by various stakeholders and is shown as the orange solid line on the map below and has been filed with the FERC for further consideration.



Continued development of the project in 2015 will include ongoing environmental research, further outreach programs, development of procurement plans for long lead time items and continued marketing of available firm capacity prior to and following the September 2015 FERC application.

APUC: CORPORATE AND OTHER EXPENSES

APUC: CORPORATE AND OTHER EXPENSES	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Corporate and other expenses:				
Administrative expenses	**$ 10.5**	$ 5.2	**$ 34.7**	$ 23.5
(Gain)/Loss on foreign exchange	**0.3**	(0.1)	**(1.1)**	(0.6)
Interest expense	**14.1**	14.4	**62.4**	53.4
Interest, dividend and other Income [1]	**0.5**	0.7	**3.2**	2.5
Write down of long lived assets	**0.3**	—	**8.5**	—
Acquisition-related costs	**1.6**	0.6	**2.6**	2.1
(Gain)/Loss on derivative financial instruments	**2.0**	(2.7)	**1.4**	(5.2)
Income tax expense	**3.7**	5.2	**16.8**	9.2

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

2014 Annual Corporate and Other Expenses

During the year ended December 31, 2014, administrative expenses totalled $34.7 million, as compared to $23.5 million in the same period in 2013. The expense increase for the period is primarily due to approximately $6.3 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company. The remaining $4.9 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the year ended December 31, 2014, interest expense totalled $62.4 million, as compared to $53.4 million in the same period in 2013. The increased interest expense is a result of new indebtedness incurred during the first half of 2014 used to partially finance new acquisitions and fund other growth initiatives.

For the year ended December 31, 2014, interest, dividend and other income totalled $3.2 million, as compared to $2.5 million in the same period in 2013, an increase of $0.7 million due to an incremental $2.5 million in rental income earned in 2014, partially offset by $1.8 million in decreased dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the year ended December 31, 2014, acquisition related costs totalled $2.6 million, as compared to $2.1 million in the same period in 2013. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the year ended December 31, 2014, loss on derivative financial instruments totalled $1.4 million, as compared to a gain of $5.2 million in the same period in 2013. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $16.8 million was recorded in the year ended December 31, 2014, as compared to an income tax expense of $9.2 million during the same period in 2013. The increase in income tax expense for the year ended December 31, 2014 is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, and other items permanently non-deductible for tax purposes.

2014 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2014, administrative expenses totalled $10.5 million, as compared to $5.2 million in the same period in 2013. The increase was primarily due to $3.9 million in additional costs incurred to administer APUC's operations as a result of the company's growth and $1.4 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company.

For the quarter ended December 31, 2014, interest expense totalled $14.1 million, as compared to $14.4 million in the same period in 2013. The decreased interest expense is a result of increased capitalization of interest expense due to the ongoing development projects during the end of period.

For the quarter ended December 31, 2014, interest, dividend and other income totalled $0.5 million, as compared to $0.7 million in the same period in 2013. Interest, dividend and other income primarily consists of $0.7 million in rental income, partially offset by $0.3 million in decreased dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the quarter ended December 31, 2014, loss on derivative financial instruments totalled $2.0 million, as compared to a gain of $2.7 million in the same period in 2013. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $3.7 million was recorded in the three months ended December 31, 2014, as compared to an income tax expense of $5.2 million during the same period in 2013. The decrease in income tax expense for the quarter ended December 31, 2014 is primarily due to a reversal of an alternative minimum tax liability accrued in prior year, which is no longer a liability based on the amended legislation in the Internal Revenue Code, offset by increased earnings from operations, increased deferred taxes on HLBV income, and a stronger U.S. dollar.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

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

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Net earnings attributable to Shareholders	$ 31.6	$ 13.2	$ 75.7	$ 20.3
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**0.5**	3.4	**5.0**	9.6
Loss from discontinued operations	**1.5**	6.7	**2.1**	42.0
Income tax expense	**3.7**	5.2	**16.8**	9.2
Interest expense	**14.1**	14.4	**62.4**	53.4
Loss / (Gain) on sale of assets	**(0.1)**	0.6	**(0.4)**	0.8
Non-cash write downs	**0.3**	—	**8.5**	—
Acquisition costs	**1.6**	0.6	**2.6**	2.1
(Gain) / Loss on derivative financial instruments	**2.0**	(2.7)	**1.4**	(5.2)
Realized gain / (loss) on energy derivative contracts	**(0.2)**	0.3	**3.6**	0.5
(Gain) / Loss on foreign exchange	**0.3**	(0.1)	**(1.1)**	(0.6)
Depreciation and amortization	**29.0**	26.9	**114.0**	96.0
Adjusted EBITDA	**$ 84.3**	$ 68.5	**$ 290.6**	$ 228.1

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind power generation facilities. The value of net tax attributes earned in the three and twelve months ended December 31, 2014 amounted to approximately $8.9 million and $27.2 million, respectively.

For the year ended December 31, 2014, Adjusted EBITDA totalled $290.6 million, as compared to $228.1 million during the same period in 2013, an increase of $62.5 million. For the quarter ended December 31, 2014, Adjusted EBITDA totalled $84.3 million, as compared to $68.5 million, an increase of $15.8 million compared to the same period in 2013.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

(all dollar amounts in $ millions)	Quarter ended December 31, 2014	Year ended December 31, 2014
Comparative Prior Period Adjusted EBITDA	$ 68.5	$ 228.1
Significant Changes:		
Generation Business Group:		
Renewable		
Increase / (decreased) hydrology resource	2.2	(2.0)
Decreased/increased wind resources for the quarter/year to date, at the U.S. Wind Facilities offset by unfavorable periodic hedge settlements shortfalls at the Minonk, Sandy Ridge and Senate facilities	3.2	2.8
Higher realized prices on sale of Renewable Energy Credits at the U.S. Wind Facilities	1.1	4.9
Start of commercial operations for the Cornwall Solar Facility	0.3	4.8
Increased wind resources at the St Leon wind facilities	0.3	3.1
Unfavorable retail pricing at AES partially offset by gains from hedge settlements and increased customer load.	1.2	(1.8)
Thermal		
Increased market prices at the Sanger and Windsor Locks Thermal Facility	0.3	1.3
Higher realized prices on sale of Renewable Energy Credits	(0.1)	0.7
Distribution Business Group:		
Increased delivery and treatment of water and wastewater systems	0.7	3.2
Increased rates at the Granite State Electric System	1.4	10.2
Changes in customer demand and higher operating expenses at the EnergyNorth and the Midstates Gas Systems	1.8	1.9
2013 Acquisition of the New England and Peach State Gas Systems	2.5	23.6
Increase earnings due to acquisition of New England Gas System's water heater rental service and the Peach State Gas System's Fort Benning operation	1.8	3.8
Administrative expense	(5.4)	(11.2)
Increased results from the stronger U.S. dollar	6.6	18.4
Other	(2.1)	(1.2)
Current Period Adjusted EBITDA	$ 84.3	$ 290.6

Reconciliation of adjusted net earnings to net earnings

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

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Net earnings attributable to Shareholders	**$ 31.6**	$ 13.2	**$ 75.7**	$ 20.3
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**1.5**	6.7	**2.1**	42.0
(Gain) / Loss on derivative financial instruments, net of tax	**1.2**	(1.6)	**0.8**	(3.1)
Realized gain / (loss) on derivative financial instruments, net of tax	**(0.5)**	(0.2)	**0.7**	(1.2)
Write down long lived assets	**0.3**	—	**8.5**	—
(Gain) / Loss on asset disposal, net of tax	**(0.1)**	0.4	**(0.3)**	0.5
(Gain) / Loss on foreign exchange, net of tax	**0.2**	(0.1)	**(0.7)**	(0.3)
Acquisition costs, net of tax	**1.0**	0.4	**1.6**	1.3
Adjusted net earnings	**$ 35.2**	$ 18.8	**$ 88.4**	$ 59.5
Adjusted net earnings per share	**$ 0.14**	$ 0.08	**$ 0.37**	$ 0.26

For the year ended December 31, 2014, adjusted net earnings totalled $88.4 million, as compared to adjusted net earnings of $59.5 million, an increase of $28.9 million as compared to the same period in 2013. The increase in adjusted net earnings for the year ended December 31, 2014 is primarily due to higher income from operations partially offset by higher interest expense, and depreciation and amortization expense as compared to the same period in 2013.

For the three months ended December 31, 2014 , adjusted net earnings totalled $35.2 million, as compared to adjusted net earnings of $18.8 million, an increase of $16.4 million as compared to the same period in 2013. The increase in adjusted net earnings for the three months ended December 31, 2014 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2013.

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

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

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

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Cash flows from operating activities	**$ 96.5**	$ 28.4	**$ 192.7**	$ 98.9
Add (deduct):				
Changes in non-cash operating items	**(33.1)**	13.5	**0.5**	47.8
Cash (provided)/used in discontinued operation	**0.9**	3.5	**1.7**	4.4
Production Tax Credits received from non-controlling interests	**—**	—	**9.0**	1.7
Acquisition costs	**1.6**	0.6	**2.6**	2.1
Adjusted funds from operations	**$ 65.9**	$ 46.0	**$ 206.5**	$ 154.9
Adjusted funds from operations per share	**0.27**	0.22	**0.92**	0.73

For the year ended December 31, 2014, adjusted funds from operations totalled $206.5 million, as compared to adjusted funds from operations of $154.9 million, an increase of $51.6 million as compared to the same period in 2013.

For the three months ended December 31, 2014, adjusted funds from operations totalled $65.9 million, as compared to adjusted funds from operations of $46.0 million, an increase of $19.9 million as compared to the same period in 2013.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
GENERATION GROUP				
Renewable	**$ 59.6**	$ 18.0	**$ 197.1**	$ 46.9
Thermal	**0.5**	1.3	**4.0**	2.6
Total Generation Business Group	**$ 60.1**	$ 19.3	**$ 201.1**	$ 49.5
DISTRIBUTION GROUP	**$ 77.4**	$ 43.4	**$ 176.8**	$ 108.9
Corporate	**4.3**	—	**54.5**	—
Total	**$ 141.8**	$ 62.7	**$ 432.4**	$ 158.4

The company's consolidated capital expenditure plan for 2015 is approximately $261.0 million. The Generation Group expects to invest approximately $107.0 million primarily in connection with the development of its existing project pipeline. The Distribution Group expects to invest approximately $147.0 million primarily to improve the reliability and efficiency of its gas and electric utility distribution systems. The Transmission Group expects to invest approximately $7.0 million for the natural gas pipeline transmission project.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, revolving credit facilities, as well as the debt and equity capital markets to finance its property, plant and equipment expenditures and other commitments.

2014 Twelve Month **Property Plant and Equipment Expenditures**

During the twelve months ended December 31, 2014 , the Generation Group incurred capital expenditures of $201.1 million, as compared to $49.5 million during the comparable period in 2013.

During the twelve months ended December 31, 2014 , the Generation Group's Renewable Energy Division spent $197.1 million in capital expenditures, as compared to $46.9 million in the comparable period in 2013. The capital expenditures primarily relate to the completion of the Cornwall Solar and St. Damase Wind Facilities, and the construction of the Bakersfield Solar and Morse Wind Projects. The Generation Group's Thermal Energy Division net capital expenditures were $4.0 million, as compared to $2.6 million in the comparable period in 2013. The capital expenditures in the year were $1.2 million at Windsor Locks and $2.8 million at Sanger.

During the twelve months ended December 31, 2014 , the Distribution Group invested $176.8 million in capital expenditures, as compared to $108.9 million during the comparable period in 2013. The capital expenditures primarily relate to the completion of a second supply line, reliability enhancements, and new business projects at the Granite State Electric System; improvement and replenishment opportunities at the CalPeco Electric System; leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to enhancing safety and reliability at the EnergyNorth, Midstates, New England, and Peach State Gas Systems; and improvement, replenishment and new business projects at the water and wastewater utilities located in Arizona and at the Pine Bluff Water System.

2014 Fourth Quarter **Property Plant and Equipment Expenditures**

During the three months ended December 31, 2014 , the Generation Group incurred capital expenditures of $60.1 million, as compared to $19.3 million during the comparable period in 2013. During the three months ended December 31, 2014 , the Generation Group's Renewable Energy Division spent $59.6 million in capital expenditures, as compared to $18.0 million in the comparable period in 2013. The capital expenditures primarily relate to completion of construction at the St. Damase Wind Facility and the continued construction at the Bakersfield Solar Project. The Generation Group's Thermal Energy Division net capital expenditures were $0.5 million, as compared to $1.3 million in the comparable period in 2013. The 2014 thermal capital expenditures consist of $0.4 million relating to Windsor Locks Thermal Facility and $0.1 million relating to Sanger Thermal Facility.

During the three months ended December 31, 2014 , the Distribution Group invested $77.4 million in capital expenditures, as compared to $43.4 million during the comparable period in 2013. The Distribution Group's investment was primarily related to reliability enhancements, and new business projects at the Granite State Electric System; improvement and replenishment opportunities at the CalPeco Electric System; leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to enhancing safety and reliability at the EnergyNorth, Midstates, New England, and Peach State Gas Systems; and improvement, replenishment and new business projects at the water and wastewater utilities located in Arizona and at the Pine Bluff Water System.

Quebec Dam Safety Act

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

The Generation Group currently estimates further capital expenditures of approximately $7.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

(all dollar amounts in $ millions)	Total	2015	2016	2017	2018
Future Estimated Bill C-93 Capital Expenditures	$ 7.9	1.0	3.1	3.5	0.3

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

The Generation Group is presently working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Belleterre Hydro Facility that are not required for power generation. The Generation Group anticipates completion of any required work on these dams by 2017.

Engineering for the Riviere-du-Loup Hydro Facility was completed in 2012. Following additional geotechnical investigation in 2014, the remediation work is now estimated at $1.1 million. Completion of the remedial work is anticipated in 2015.

The dam safety study and a detailed condition assessment for the St. Alban Hydro Facility have been completed. The Generation Group anticipates engineering and regulatory review for the remediation of the main dam to be completed in 2015, with remedial work in 2016 to 2017.

On May 18, 2014, the Donnacona Hydro Facility experienced ice damage during the spring thaw and has been shut down. The Generation Group had previously planned capital expenditures for the Donnacona Hydro Facility in 2015 and 2016 in the amount of $7.8 million. It has been determined, in consultation with its 3rd party engineers, that a dam re-build is required to return the facility to operation. The Generation Group is currently evaluating environmental permitting and rebuild scenarios. Consequently, the Generation Group does not anticipate any near-term expenditures related to Bill C-93 compliance of the existing structure.

In addition to the Bill C-93 related dam remediation work, the Generation Group has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

LIQUIDITY AND CAPITAL RESERVES

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

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its operating groups as at December 31, 2014 under the Facilities:

	As at December 31, 2014				As at Dec 31 2013
(all dollar amounts in $ millions)	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	$ 65.0	$ 350.0	$ 232.0	$ 647.0	$ 477.7
Funds drawn on Facilities	—	(23.4)	(23.9)	(47.3)	(210.2)
Letters of Credit issued	(10.8)	(96.0)	(7.0)	(113.8)	(64.9)
Funds available for draws on the Facilities	**$ 54.2**	**$ 230.6**	**$ 201.1**	**$ 485.9**	$ 202.6
Cash on Hand				9.3	13.8
Total liquidity and capital reserves	**$ 54.2**	**$ 230.6**	**$ 201.1**	**$ 495.2**	$ 216.4

As at December 31, 2014, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had $10.8 million of outstanding letters of credit. The facility matures on November 19, 2016 and is subject to customary covenants.

As at December 31, 2014, the $350.0 million Generation Credit Facility had drawn $23.4 million and had $96.0 million in outstanding letters of credit. On July 31, 2014, the Generation Group increased the credit available under its credit facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next four years. In addition to the larger size, the maturity of the credit facility has been extended from three to four years extending to July 31, 2018.

As at December 31, 2014, the Distribution Group's $232.0 million (U.S. $200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") had drawn $23.9 million (U.S. $20.6 million) and had $7.0 million (U.S. $6.0 million)of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants

Long Term Debt

On January 17, 2104, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "Generation Debentures") pursuant to a private placement in Canada and the United States. The Generation 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 Generation Group entered into a fixed for fixed cross currency swap, coterminous with the Generation 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%.

On December 31, 2014, the U.S. $19.2 million senior debt for the Sanger Thermal Facility was repaid.

As at December 31, 2014, the weighted average tenor of APUC's total long term debt is approximately 8.0 years with an average interest rate of 4.9%.

Contractual Obligations

Information concerning contractual obligations as of December 31, 2014 is shown below:

(all dollar amounts in $ millions)		Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long-term debt obligations	$	1,280.0	9.1	91.0	218.8	961.1
Advances in aid of construction	$	81.1	1.1	—	—	80.0
Interest on long-term debt obligations	$	438.3	64.2	125.3	102.1	146.7
Purchase obligations	$	267.9	267.9			
Environmental obligation	$	72.6	19.6	36.6	6.1	10.3
Derivative financial instruments:						
Cross currency swap	$	36.3	1.5	3.0	2.4	29.4
Interest rate forward	$	4.7	—	—	4.7	—
Interest rate swap	$	1.4	1.4	—	—	—
Energy derivative contracts	$	2.9	2.3	0.6	—	—
Purchased power	$	118.2	118.2	—	—	—
Gas delivery, service and supply agreements	$	264.3	52.8	68.0	55.3	88.2
Long term service agreements	$	637.3	28.6	64.7	62.9	481.1
Capital projects	$	22.0	22.0	—	—	—
Operating leases	$	121.1	5.6	9.6	8.5	97.4
Other obligations	$	40.5	9.9	0.9	—	29.7
Total obligations	**$**	**3,388.6**	**$ 604.2**	**$ 399.7**	**$ 460.8**	**$ 1,923.9**

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2014, APUC had 238,149,468 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 September 16, 2014, APUC completed the 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 offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the offering. As a result, APUC issued 19,389,000 common shares under the 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.

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, 2014, APUC had outstanding:

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

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares of APUC. As at December 31, 2014, 63.8 million common shares representing approximately 27% of total shares outstanding had been

registered with the Reinvestment Plan and 2,262,885 shares were issued during the year ended December 31, 2014. During the quarter ended December 31, 2014, 665,172 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 15, 2015, an additional 706,680 common shares were issued under the Reinvestment Plan.

Emera subscription receipts

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

On October 7, 2014, the Company issued 8,708,170 Subscription Receipts of APUC at a purchase price of $8.90 per Subscription Receipt for an aggregate subscription price of $77.5 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Odell Wind Project in Minnesota (the "Odell Acquisition"). The proceeds of the subscription are intended to be used by APUC to partially finance the Odell Acquisition and the completion of the Odell Wind Project. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on November 14, 2015 (the first anniversary of the closing of the Odell Acquisition) or the commercial operation date of the Odell Wind Project, whichever is first to occur.

On December 2, 2014, the Corporation issued 3,316,583 subscription receipts of APUC at a purchase price of $9.95 per subscription receipt for an aggregate subscription price of $33.0 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Park Water Company in Montana (the "Park Water Acquisition"). The proceeds of the subscription are intended to be used by APUC to partially finance the Park Water Acquisition. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on December 29, 2015 (the first anniversary of the closing of the subscription transaction) or the closing of the Park Water Acquisition, whichever is first to occur.

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

As at March 15, 2015, in total, Emera owns 50,126,766 APUC common shares representing approximately 21.0% of the total outstanding common shares of the Company, and there are 12,024,753 subscription receipts currently held by Emera. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE BASED COMPENSATION PLANS

For the three and twelve months ended December 31, 2014, APUC recorded $1.1 million and $3.2 million, respectively, in total share-based compensation expense, as compared to $0.6 million and $2.0 million, respectively, for the same period in 2013. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $2.1 million and $2.4 million, respectively, and are expected to be recognized over a period of 1.71 and 1.61 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the year, the Company issued 969,998 options to employees of the Company.

As at December 31, 2014, a total of 5,537,127 options had been issued and outstanding under the plan.

Performance Share Units

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

During the year, the Company settled 11,406 vested PSUs for $0.2 million in cash. The plan provides for settlement in cash or shares at the election of the Company. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards. During the year, the Company issued 407,962 PSUs to executives and employees of the Company.

As at December 31, 2014, a total of 440,086 PSU's have been granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards. During the year, the Company issued 35,455 DSUs to the directors of the Company.

As at December 31, 2014, a total of 110,241 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the year, the Company issued 93,598 common shares to employees under the ESPP plan.

As at December 31, 2014, a total of 240,411 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

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC, are indirect shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of the Company and several related affiliates (collectively the "Parties"). Prior to 2010, there were several related party transactions and co-owned assets which existed pursuant to the external management structure before the internalization of management which occurred on December 21, 2009.

In 2011, the Board formed an independent committee ("Independent Board Committee") and initiated a process to review all of the remaining business associations with the Parties in order to reduce and/or eliminate these relationships. The Independent Board Committee engaged independent consultants and advisors to assist with this process and to provide advice in respect thereof. Specifically, the independent advisors provided advice to the Independent Board Committee in relation to the valuations of the generating assets, tax and legal matters.

The process, initiated in 2011, was completed in November 2013 and all related party transactions, except as noted below, between APUC and the Parties have been addressed to the satisfaction of the Independent Board Committee and the Board as discussed below.

The following describes the business associations and resolution with APMI and Senior Executives:

Due to and from related parties

Effective December 31, 2013, APUC paid the Parties $1.8 million in connection with outstanding fees and the Parties paid APUC $0.8 million in connection with reimbursement of expenses. As at December 31, 2014, $0.047 million (2013 - $0.047 million) remains due from Algonquin Power Systems Ltd., a corporation partially owned by the Senior Executives.

Equity interests in Rattle Brook Hydro, Long Sault Hydro, and BCI Thermal Facilities

The Parties own interests in three power generation facilities in which APUC also has an interest. A brief description of the facilities is provided as follows:

- Rattle Brook is a 4 MW hydroelectric generating facility (“Rattle Brook”) constructed in 1998 in which APUC owns a 45% interest and Senior Executives hold an equity interest in the remaining 55%.
- Long Sault Hydro Facility is an 18MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in Long Sault Hydro Facility by way of subscribing to two notes from the original partners. One of the original partners, an affiliate of APMI, is entitled to receive 5% of the equity cash flows commencing in 2014.
- Brampton Cogeneration ("BCI Thermal Facility") is an energy supply facility which sells steam produced by EFW. In 2004, APMI acquired 50 Class B partnership units in BCI Thermal Facility entitling them to 50% of the cash flow above 15% return on the investment.

Effective December 31, 2013, APUC acquired the Parties’ shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18MW Long Sault Hydro Facility and the partnership interest in the BCI Thermal Facility plant for an amount equal to $3.8 million. As APUC already consolidates Long Sault Hydro Facility as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10.7 million in regards to tax attributes acquired with the partnership interests and an adjustment of $14.6 million to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4 MW Rattle Brook Hydro Facility to the Parties for gross proceeds $3.4 million for a loss on sale, net of tax of $0.4 million.

APUC earned a fee of $0.4 million from APC during the year ended December 31, 2013 related to settlement of the related party transactions.

St. Leon LP Units

Third party investors, including Senior Executives, previously held 100 Class B limited partnership units issued by the St. Leon Limited Partnership, which is the legal owner of the St. Leon Wind Facility.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units (note 11) including 36 units held indirectly by Senior Management. The Series C preferred shares provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee. As of January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2014 were $0.3 million (2013 - $0.3 million). In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease for nominal consideration. There is no further related party matter in relation to an office lease.

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $0.5 million. As at December 31, 2013, the Independent Board Committee and the Parties agreed that all future utilization of chartered aircraft would be undertaken through a third-party charter operator at fair market value and under arrangements in which the Senior Executives have no interest. Final arrangements in this regard had not been completed as at December 31, 2014. During the year ended December 31, 2014, APUC reimbursed direct costs in connection with the use of the aircraft of $0.7 million.

Trafalgar

The Company owns 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 affiliate of APMI moved to foreclose on the assets. Subsequently, Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2.0 million in legal fees prior to 2004.

In 2004, the Board reimbursed APMI $1.0 million of the total third party legal fees (which to that point totalled $2.0 million), and APUC agreed to fund future legal fees, third party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

A member of the Board is an executive at Emera. Related Party Transactions between APUC and Emera are discussed below:

- For the year ended December 31, 2014, the Company sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $5.8 million (2013 - U.S. $6.0 million). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3.0 million and a letter of credit in an amount of U.S. $0.1 million, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine. For the year ended December 31, 2014, the Company purchased natural gas amounting to U.S. $5.0 million (2013 - U.S. $1.3 million) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1.0 million to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks Thermal Facility. There has not been any transaction under this contract in the last three years.

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

Other

A spouse of one of the Senior Executives provided market research consulting services to certain subsidiaries of the Company. During the year ended December 31, 2014, APUC paid $0.192 million (2013 - $0.045 million) in relation to these services.

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. Key risks and associated mitigation strategies are reviewed by the Executive Risk Steering Committee on a monthly basis and presented to the Board of Directors on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, security (physical and cyber), operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

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

The development and execution of risk treatment plans are actively monitored by the ERM team through a centralized risk register software application. APUC's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and reported to the Board audit committee on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Executive Risk Steering Committee, and the Board of Directors for consideration.

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

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

Treasury Risk Management

Foreign Currency Risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 78% of EBITDA in 2014 and 77% 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 $22.8 million ($0.10 per share) on an annual basis.

In light of the currency profile of its operations, APUC changed the currency of its dividend to U.S. dollars in the third quarter of 2014. APUC further manages currency risk through the matching of U.S. long term debt to finance its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing cost. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. APUC may from time to time enter into short term foreign currency derivative contracts to hedge exposure of anticipated transactions denominated in a foreign currency.

Market Price Risk

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

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

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

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

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

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

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

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

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2014, the Generation Group had not entered into any such hedges.

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

Credit/Counterparty Risk

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

APUC does not believe the credit risk of default by counterparties to its long term power purchase contracts to be significant, as approximately 84.7% of the Generation Group's revenues are earned from large utility customers having a credit rating of Baa1 or better by Moody's Rating Services or BBB+ or higher by S&P Rating Services. The following chart sets out the Generation Group's significant customers, their credit ratings and percentage of total revenue associated with the customer:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percent of Divisional Revenue
Generation Group - Renewable Energy			
PJM Interconnection LLC	Aa3	49.0	33.6%
Manitoba Hydro	Aa1	31.1	21.4%
Hydro Quebec	Aa2	22.6	15.5%
Ontario Electricity Financial Corporation	Aa2	17.8	12.2%
Emera Maine [2]	N/A	8.0	5.5%
Total – Renewable Energy		**$ 128.5**	**88.2%**
Generation Group - Thermal Energy			
Pacific Gas and Electric Company	Baa1	19.8	46.1%
Connecticut Light and Power	Baa1	23.2	53.9%
Total – Thermal Energy		**$ 43.0**	**100.0%**
Total – Generation Group		**$ 171.5**	**84.7%**

[1] Ratings by Moody's or Standard & Poor's as of February 2015.

[2] Maine Public Service is a subsidiary of Emera which has a corporate rating of BBB+.

The remaining revenue is primarily earned by the Distribution Group. In this regard, the credit risk attributed to the Distribution Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $5.9 million which is spread over approximately 97,000 connections, resulting in an average outstanding balance of approximately $60 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $62.0 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. 24.3 million. The natural gas and electrical utilities, respectively, derive over 91% and 87% of their revenue from residential customers.

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

Interest Rate Risk

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

- The Corporate Credit Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

- The Generation Credit Facility had $23.4 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Distribution Credit Facility had $23.9 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Generation Group is party to an interest rate swap whereby the group pays a fixed interest rate of 4.47% on a notional amount of $60.5 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. This interest rate swap is not being accounted for as a hedge and, consequently, changes in fair value are recorded in earnings as they occur. As a result, a 100 basis point change in the variable rate would impact derivative gains/losses by $0.01 million.
- The Shady Oaks Senior Debt Facility had $88.2 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.9 million annually.

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. The interest rate swap, although not designated as a hedge, serves to partially offset interest rate movements against the variable pay portion of the Company's debt.

To mitigate refinancing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter, the Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment will apply to this transaction. Consequently, changes in fair value, to the extent deemed effective, will be recorded into Other Comprehensive Income.

Tax Risk and Uncertainty

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

Unit Exchange Transaction

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

Subsequent to the Balance Sheet date, APUC received a proposal letter from the Canada Revenue Agency ("CRA") which outlines its intention to challenge the tax consequences of APUC's 2009 Unit Exchange. CRA is seeking to apply the acquisition of control rules or the general anti-avoidance rules of the Income Tax Act (Canada) the effect of which would be to deny APUC of the benefit of the tax attributes assumed as part of the Unit Exchange Transaction.

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17.5 million. Additionally, assuming the 2014 taxation year will be similarly reassessed, a further payment of approximately $3.1 million would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar notice of reassessment for such years and APUC were to appeal it.

Should APUC be successful in defending its position, all such payments plus applicable interest, will be refunded to APUC. If the CRA is successful, APUC will be required to pay the balance of the taxes assessed (plus applicable interest and any applicable penalties).

APUC has 90 days from the date of any Notice of Reassessment to prepare and file a Notice of Objection, which would be reviewed by the CRA's appeals division. If the CRA appeals division does not allow APUC's initial appeal, APUC has the option to file its case with the Tax Court of Canada. APUC anticipates that legal proceedings through the various tax courts could take approximately two to four years.

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from $nil to $45.0 million.

The impact of the proposal on APUC's tax provision has been considered by management; however, management continues to believe that the most likely outcome has not changed and it is more likely than not, that APUC will be successful in defending its position. On this basis, APUC's 2014 financial statements do not include the impact of a potential reassessment. Until the matter is resolved with CRA, or should new facts arise that would result in a change to management's assessment of the most likely outcome, any future deposit tax payments made by APUC will be recorded to the balance sheet and will not impact either adjusted funds from operations or net earnings.

On a consolidated basis, APUC and its Canadian subsidiaries have tax attributes that are available to reduce or eliminate cash taxes. Should the CRA ultimately be successful in the appeal process, APUC will seek to refile prior year tax returns and accelerate the use of such tax attributes to minimize any actual cash taxes that would otherwise be owed as a result of the reassessment of the tax consequences of the Unit Exchange.

Liquidity Risk

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

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

As at December 31, 2014, APUC and its subsidiaries had a combined $485.9 million of committed and available revolving credit facilities remaining and $9.3 million of cash resulting in $495.2 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.35 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of common share dividends paid during the year ended December 31, 2014, cash provided by operating activities exceeded common share dividends declared by 2.2 times and Adjusted Cash From Operations exceeds common share dividends by 3.4 times.

The current and long term portion of debt totals approximately $1,280.0 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

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

Commodity Price Risk

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

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 174,000 MW-hrs in fiscal 2015, of which 90,000 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 80,000 MW-hrs of its energy requirements at the ISO-NE summer spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 174,000 MW-hrs. The risk associated with the expected market purchases of 80,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 90% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $65 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.5 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 take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

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

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

OPERATIONAL RISK MANAGEMENT

Mechanical and Operational Risks

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

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

The Generation Group's wind assets could on catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions (e.g. El

Nina), which will lower wind levels below our PPA and hedge minimum production levels. Production risks associated with the wind turbine generators is mitigated by properly maintaining the units using long term maintenance agreements with the turbine O&M's, which provide for regular inspections and maintenance of property and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

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

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

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

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

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

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

Regulatory Risk

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

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

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

Condemnation Expropriation Proceedings

The Distribution Group's 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 just and fair compensation be paid to the Distribution Group and the Distribution Group believes such compensation would reflect fair market value for any assets that are taken. Notwithstanding the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and therefore there is no assurance that the value received for assets taken will be in excess of book value. In 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Mountain Water Company is the water utility in Western Montana serving the municipality of Missoula owned by Park Water Company. Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will be successful in its condemnation efforts. If the city of Missoula is successful in its condemnation efforts, the quantum of compensation to be paid by the city of Missoula for such taking will be subsequently determined by a valuation hearing by the courts. In respect of such potential valuation hearing, expert reports have been prepared by Mountain Water Company which indicate a fair value of Mountain Water Company of between US$116.0 million and US$141.0 million.

Asset Retirement Obligations

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

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

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

Environmental Risks

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

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

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

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

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

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

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

Prior to their acquisition by the Distribution Group, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Distribution Group is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the NHDES. The Distribution Group believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental cleanup activities will be $72.6 million which, at discount rates ranging from 2.1% to 3.4%, represents $72.3 million on a discounted basis, as the Distribution Group's estimate of costs for known issues that has been accrued at December 31, 2014. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2014 the Company has reflected a regulatory asset of $102.7 million for the remediation of the MGP and related sites.

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

Cycles and Seasonality

Generation Group

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

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

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

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

Distribution Group

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

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

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

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

Development and Construction Risk

The Generation Group actively engages in the development and construction of new power generation facilities. The current pipeline of projects either currently in construction or in development is $1.2 billion and are mainly renewable solar and wind projects. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. Examples of inherent risks pertaining to power generation facility development can include: technical issues with the interconnection utility, unfavorable permitting results or delays emanating from State, Provincial or Federal agency interface, construction delays or cost overruns, equipment performance outside of expectations, and land owner disputes. The Generation Group mitigates these risk through its due diligence processes, sound project management principals and appropriate contingency plans and reserves.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to

accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

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

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

Obligations to Serve

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

Litigation Risks and Other Contingencies

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

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain subsidiary entities of APUC, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that APUC was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against APUC were dismissed by summary judgment. On October 22, 2009, Trafalgar filed an appeal from the November 6, 2008 summary judgment to the United States Court of Appeals for the Second Circuit. As discussed further below, as the proceedings continued, the United States Second Circuit Court of Appeals, among other things, (i) on November 2, 2010 dismissed the claims against APUC in the civil proceedings; and (ii) on January 30, 2013, held that Algonquin has a security interest in Trafalgar's engineering malpractice claim and its proceeds.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving APUC judgment on its claims. Trafalgar asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied Trafalgar's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of APUC's remedies under the loan documents, including the calculation of the debt and the disposition of collateral. The District Court entered judgment in favor of APUC with regard to the default and APUC's entitlement to recourse to the collateral, but without determining the amount due under the note. The District Court then closed the case.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals, and in the alternative, sought to have the Second Circuit certify a legal question to the New York State Court of Appeals. The Second Circuit denied the petition and certification request which petition was denied on June 17, 2013. On September 16, 2013, Trafalgar filed a Petition for a Writ of Certiorari with the United States Supreme Court. Algonquin filed a brief in opposition to the Petition on October 18, 2013. On December 2, 2013, the United States Supreme Court denied Trafalgar's petition for a Writ of Certiorari. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been denied

without prejudice to re-filing the motion after the court determines the amount of Algonquin's claim and the validity of any defenses to the claim. Algonquin and Trafalgar have each filed motions with the Court seeking a determination of those issues. Those motions are under consideration by the Court.

The Court has approved the sale of all seven of the Trafalgar facilities. Of the seven, one has closed while the other six is anticipated to close upon obtaining regulatory approval. The parties are attempting to resolve this matter through good faith settlement negotiations.

Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (the "Québec AG") filed suit in Québec Superior Court against Algonquin Dévelopment (Côte Ste-Catherine) Inc. (Dévelopment Hydromega), a predecessor company to an a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Dévelopment Côte Ste-Catherine Inc. had been paying to Seaway Management under the water lease relating to the Côte Ste-Catherine hydroelectric generating facility. Algonquin Dévelopment (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011, the Québec Court of Appeal ordered Algonquin Dévelopment (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Dévelopment (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $6.0 million. The parties are attempting to resolve this matter through good faith negotiations.

Long Sault global adjustment claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("TMC") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. The Application was heard in May 2014. 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. The OEFC has until April 13, 2015 to appeal this decision.

Dimos and Katsekas Breach of Contract Claim

On September 30, 2013, Dimos and Katsekas previous owners of the Clement Dam Hydroelectric, LLC. ("Clement Dam Hydro Facility"), filed a demand for arbitration with Algonquin Power Fund (America) Inc. ("APFA") alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for $1,345,257 for alleged breach of such agreements and $155,821 for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements. An arbitration hearing date is scheduled for May, 2015.

The Royalty Agreement obligations were guaranteed by the Clement Dam Hydro Facility pursuant to a guaranty. On December 14, 2014, Dimos and Katsekas filed a complaint against the Clement Dam Hydro Facility which seeks to enforce certain obligations under a guaranty. In the event the claimants prevail against APFA in the aforementioned arbitration, and APFA does not pay any judgment rendered against it, claimants will pursue their claims against the Clement Dam Hydro Facility. APFA is defending the Clement Dam in this matter pursuant to the sale agreement with the purchaser of the Clement Dam Hydro Facility. At present, the litigation has been stayed pending the outcome of the arbitration proceeding.

Synergics Energy Services, LLC, Breach of Contract Claim

On September 4, 2013, the plaintiff, previous owners of the Great Falls Hydro Facility, filed a complaint for alleged breach of the 2000 purchase and sale agreement and failure to pay a transfer payment thereunder in the event of the sale of the hydro facility. The claim is for $3,000,000 for alleged breach of the 2000 purchase and sale agreement. The case has been settled.

Conex Energy-Canada, LLC and Conex Energy, Inc. Breach of Contract Claim

On October 31, 2013, the plaintiffs filed a complaint for, among other things, alleged breach of a confidential agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar Facility. On March 3, 2014, Algonquin brought a motion to dismiss the case. The Court has since dismissed the case.

Bryson School District in Texas Property Taxes Claim

On February 10, 2014, the Generation Group received correspondence from the Bryson School District (the "School District") in Texas regarding Senate Wind LLC's property taxes claiming the Senate Wind Facility owes an additional $2.2 million of property taxes based on an indemnity in the 2010 agreement with the School District. Senate Wind LLC and the District have settled this matter.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2014:

(all dollar amounts in $ millions except per share information)	1st Quarter 2014	2nd Quarter 2014	3rd Quarter 2014	4th Quarter 2014
Revenue	$ 343.5	$ 189.3	$ 151.9	$ 259.3
Adjusted EBITDA	97.5	66.4	41.4	84.3
Net earnings / (loss) attributable to shareholders from continuing operations	35.6	15.3	(6.1)	33.1
Net earnings / (loss) attributable to shareholders	35.9	14.6	(6.3)	31.6
Net earnings / (loss) per share from continuing operations	0.16	0.06	(0.04)	0.13
Net earnings / (loss) per share	0.17	0.06	(0.04)	0.13
Adjusted net earnings	36.8	16.5	(0.4)	35.2
Adjust net earnings per share	0.17	0.07	(0.01)	0.14
Total Assets	3,652.7	3,561.9	3,808.5	4,113.7
Long term debt[1]	1,409.4	1,389.3	1,413.5	1,280.0
Dividend declared per common share	0.09	0.09	0.10	0.10

	1st Quarter 2013	2nd Quarter 2013	3rd Quarter 2013	4th Quarter 2013
Revenue	$ 193.3	$ 148.8	$ 127.9	$ 205.3
Adjusted EBITDA	62.8	56.5	40.2	68.5
Net earnings / (loss) attributable to shareholders from continuing operations	20.3	15.8	6.3	19.8
Net earnings/(loss) attributable to shareholders	19.2	(18.1)	6.0	13.2
Net earnings / (loss) per share from continuing operations	0.09	0.08	0.02	0.09
Net earnings/(loss) per share	0.09	(0.09)	0.02	0.06
Adjusted net earnings	19.6	15.4	6.9	18.8
Adjust net earnings per share	0.09	0.08	0.03	0.08
Total Assets	3,476.5	3,201.8	3,156.4	3,476.5
Long term debt[1]	1,255.5	1,091.5	1,092.0	1,255.6
Dividend declared per common share	0.08	0.09	0.09	0.09

[1] Long term debt includes current and long term portion of 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 $127.9 million and $343.5 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $35.9 million and a net loss of $18.1 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.

ISSUANCE OF FOURTH QUARTER AND YEAR END FINANCIAL RESULTS

Shortly before the originally scheduled release of its 2014 financial results, APUC became aware of certain anonymous, unproven allegations regarding certain APUC personnel. APUC shared the allegations with its auditors, and delayed releasing its financial results in order to consider, together with the auditors, whether certain of the allegations which related to Algonquin's financial reporting and related practices could impact its financial results. This assessment, which was led by a committee of independent directors with the assistance of independent legal and accounting advisors was completed and on March 16, 2015 APUC released its financial results, having determined that the allegations did not impact APUC's financial results. The committee's investigation into the allegations which are not related to APUC's financial reporting and related practices is continuing to be dealt with in a confidential manner in accordance with APUC's complaint-handling policies.

DISCLOSURE CONTROLS

At the end of the fiscal year ended December 31, 2014, 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, 2014, 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, 2014, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) published

an updated Internal Control - Integrated Framework (2013) and related illustrative documents. The company adopted the new framework in 2014.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2014 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, 2014.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of

depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

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

Estimated useful lives and recoverability of Long-Lived Assets, Intangibles and Goodwill

The provisions for depreciation of property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets. 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. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Changes in circumstances, market conditions and estimates of future cash flows could negatively affect the recovery of APUC's assets and result in an impairment charge.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

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

Unbilled Energy Revenues

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

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does,

whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and post-employment benefit plans for qualifying employees in the related acquired businesses. The obligations and related costs are calculated using actuarial concepts, which include critical assumptions related to the discount rate, 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 tables (RP-2014) and the mortality improvement scale (MP-2014) that were recently released by the Society of Actuaries in the current year assumptions. This change resulted in an increase to the pension and post-employment obligations of approximately U.S. $16.5 million.

Business Combinations

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

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

Exhibit 99.5

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our Firm under the caption “Interests of Experts” and to the use in this Annual Report on Form 40-F of our report dated March 16, 2015, with respect to the consolidated balance sheet of Algonquin Power & Utilities Corp. as at December 31, 2014 and 2013, and the consolidated statements of operations, comprehensive income, equity, and cash flows for the two years then ended, and our report dated March 16, 2015 with respect to the effectiveness of internal control over financial reporting of Algonquin Power & Utilities Corp. as at December 31, 2014.

We also consent to the incorporation by reference of our reports dated March 16, 2015 in the Registration Statement (From S-8 No. 333-177418) pertaining to Algonquin Power &Utilities Corp

/s/ Ernst & Young, LLP

Toronto, Canada
March 30, 2015

Chartered Professional Accountants
Licensed Public Accountants



Exhibit 99.6

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 30, 2015

By: /s/ Ian E. Robertson

Name: Ian E. Robertson

Title: Chief Executive Officer

Exhibit 99.7

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 30, 2015

By: /s/ David Bronicheski

Name: David Bronicheski

Title: Chief Financial 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, 2013 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 30, 2015

By: /s/ Ian Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.9

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, 2013 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 30, 2015

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